TAMPERE UNIVERSITY OF TECHNOLOGY

KAI KINNUNEN

DEVELOPMENT OF NETWORK INFORMATION AND DISTRIBUTION MANAGEMENT SYSTEMS FROM THE ASPECT OF REPORTING REQUIREMENTS

Master of Science Thesis

Examiner: Professor Pekka Verho
Thesis examiner and topic approved in the Faculty of Computing and Electrical Engineering Council meeting 5th March 2014

ABSTRACT

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Finnish Distribution System Operators (DSO) are required to report detailed outage and network asset data from their distribution networks for Energy Authority annually as a part of economic regulation. According to the new Electricity Market Act, maximum outage duration in the town plan area is six hours and 36 hours in other area, caused by storm or snow load. Due to new law, DSOs are obligated to prepare distribution network development plans for authority every two years, starting from 2014. In the development plans, DSOs are required to describe the methods to fulfill the set distribution reliability requirements and report information of their existing and planned distribution network.

In addition to Energy Authority, also Finnish Energy Industries (Energiateollisuus ry, ET) obligates DSOs to report information from their distribution networks annually. Onwards 2015, outages are required to be reported metering point-specifically.

Due to new and tightened requirements, DSOs used computer systems; Network Information Systems (NIS) and Distribution Management Systems (DMS) need development, enabling proper and accurate data gathering and reporting.

As an outcome of this thesis, several methods to ABB MicroSCADA Pro DMS600 Network Editor (DMS600 NE) and Workstation (DMS600 WS) were developed, enabling proper data reporting. Two additional tools for environmental analysis of the network assets were developed as a part of the thesis. Analysis functions of developed tools are based on Esri shapefiles and open data utilization. Most of the developed solutions and methods were implemented to the DMS600 software during the thesis but some of the solutions were left only in specification or theoretical level. Also few open questions of implementations still remain and future development is needed.

As a part of this thesis, several new reports for Energy Authority were created. DMS600 software uses Microsoft's SQL Reporting Services-based reporting tool for DSOs' reporting measures, providing necessary outage and asset reports by embedded SQL queries from DMS600's databases.

TIIVISTELMÄ

TAMPEREEN TEKNILLINEN YLIOPISTO
Sähkötekniikan koulutusohjelma
KINNUNEN, KAI: Verkkotieto- ja käytöntukijärjestelmien kehittäminen raportointivaatimusten näkökulmasta
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Osana taloudellista valvontaa suomalaiset sähköverkkoyhtiöt ovat velvoitettuja raportoimaan yksityiskohtaista tietoa jakelukeskeytyksistä ja verkosto-omaisuudestaan Energiavirastolle vuosittain. Uuden sähkömarkkinalain mukaan myrskyn tai lumikuorman aiheuttama vika jakeluverkossa ei saa aiheuttaa yli kuuden tunnin keskeytystä asemakaava-alueella eikä yli 36 tunnin keskeytystä asemakaava-alueen ulkopuolella. Uuden sähkömarkkinalain seurauksena jakeluverkkoyhtiöt joutuvat toimittamaan sähkönjakeluverkon kehittämissuunnitelman kahden vuoden välein Energiavirastolle vuodesta 2014 alkaen. Kehittämissuunnitelmissa verkkoyhtiön tulee kuvata menetelmät, joilla jakeluverkkoa aletaan kehittämään asetettujen määräysten täyttäväksi ja myös raportoimaan tietoa nykyisestä ja suunnitellusta verkosta.

Energiaviraston lisäksi suomalaiset verkkoyhtiöt joutuvat raportoimaan tietoja jakeluverkoistaan myös Energiateollisuus ry:lle (ET) vuosittain. Vuodesta 2015 alkaen ET vaatii, että keskeytykset raportoidaan käyttöpaikkakohtaisesti.

Uusista tiukentuneista raportointivaatimuksista johtuen myös jakeluverkkoyhtiöiden käyttämät verkkotietojärjestelmät (VTJ) ja käytöntukijärjestelmät (KTJ) vaativat kehittämistä, jotta vaadittavat tiedot pystytään keräämään sekä raportoimaan tarkasti ja oikein.

Työn tuloksena kehitettiin useita menetelmiä ABB MicroSCADA Pro DMS600 Network Editoriin (DMS600 NE) ja Workstationiin (DMS600 WS), jotka mahdollistavat vaadittujen tietojen raportoinnin oikealla tavalla. Osana diplomityötä kehitettiin kaksi lisätyökalua, joiden avulla voidaan suorittaa verkosto-omaisuuden ympäristöanalyysi. Kehitettyjen työkalujen analysointitoiminnot perustuvat Esri shape –formaatissa olevan taustamateriaalin ja avoimen datan käyttöön. Suurin osa työssä kehitetyistä menetelmistä toteutettiin DMS600-tuotteeseen diplomityön aikana, mutta osa ratkaisuista jäi suunnitelma- tai teoriatasolle. Diplomityö jätti jälkeensä myös avoimia kysymyksiä ja jatkokehittämistä tarvitaan.

Osana diplomityötä luotiin useita Energiaviraston vaatimia raportteja. Verkkoyhtiöiden raportointi DMS600-ohjelmistolla on toteutettu Microsoftin SQL Server Reporting Services –työkalulla. Raportointityökalu tarjoaa tarvittavat keskeytys- ja verkosto-omaisuusraportit käyttäen upotettuja SQL-kyselyitä DMS600:n tietokannoista.

PREFACE

This Master of Science Thesis was written for Tampere University of Technology (TUT) and ABB Oy Power Systems, Network Management. The examiner of the thesis was Professor Pekka Verho, who I would like to thank for his expert guidance as well as for interesting lectures during my studies at TUT. The supervisor of the thesis from ABB Oy was Lic.Tech. Pentti Juuti, to whom I would like to express my most humble thanks for giving me such an interesting subject and valuable advices during my writing process. Many thanks go also to my superior M.Sc. Ilkka Nikander.

I would like to thank my colleagues for their support during this thesis, especially M.Sc. Risto-Matti Keski-Keturi who advised me with C# programming and M.Sc. Jarno Hakala for many interesting conversations about developed methods and development needs as well as for helping me with SSRS related issues. Many thanks also to Mr. Erkka Martikainen for further development and implementation of the developed tools.

I would also like to thank the interviewed persons from the different distribution companies; Ari Kartaslammi, Tero Salonen, Matti Virtanen and Jouni Puikko from Leppäkosken Sähkö Oy, Markku Pouttu and Arttu Ahonen from Koillis-Satakunnan Sähkö Oy and Risto Pirinen, Pasi Jokinen, Timo Patana and Jouni Perälä from Oulun Seudun Sähkö Oy. Thank you for useful comments and contribution to the thesis!

Finally I wish to express my deepest gratitude to my family and friends who have supported me in ups and downs, not only during my studies and this thesis, but also during my whole life. Thank you!

Tampere, 7^{th} October 2014

Kai Kinnunen

CONTENTS

SYMBOLS AND ABBREVIATIONS

SYMBOLS

a	Per-unit cost value for the power not supplied [€/kW] or number of metering points that experienced interruption [pcs]
AJK_t	Customer's average annual number of interruptions weighted by annual energies caused by delayed autoreclosings in the year t [pcs]
$A_{t,i}$	Age of the network component i in the year t
b	Per-unit cost value for the energy not supplied for customer j [€/kWh]
$C_f(t)$	Failure costs
$C_i(t)$	Investment costs
C_j	Cost of the energy and power not supplied
$C_m(t)$	Maintenance costs
$CN_{(k \geq S)}$	Total number of customers that experienced single interruption with duration longer than or equal to S hours
$CN_{(k \geq T)}$	Total number of customers that experienced interruptions with total durations longer than or equal to T hours
$CN_{NTPA(k \geq 36h)}$	Total number of customers not located in the town plan area that experienced an interruption with duration longer than or equal to 36 hours
$CN_{TPA(k \geq 6h)}$	Total number of customers located in the town plan area that experienced an interruption with duration longer than or equal to six hours
$C_o(t)$	Operational costs (including power losses, labor, stores and equipment)
$Empk$	Total number of LV networks affected by interruptions weighted by LV networks' annual energies
ENS_j	Energy not supplied for customer j due to an outage
$h(i,j)$	Interruption duration for LV networks [h]
h_{AJK}	Unit cost for delayed autoreclosings in the 1-70 network in the year t in the value of year 2005 [€/kW]
h_E	Unit cost for interruption duration in the value of year 2005 [€/kWh]
$h_{E,odott}$	Unit cost for unanticipated interruption duration in the value of year 2005 [€/kWh]
$h_{E,suunn}$	Unit cost for planned interruption duration in the value of year 2005 [€/kWh]
h_{PJK}	Unit cost for rapid autoreclosings in the 1-70 kV network in the year t in the value of year 2005 [€/kW]

h_W	Unit cost for interruption in the value of year 2005 [€/kW]
$h_{W,odott}$	Unit cost for unanticipated interruption in the value of year 2005 [€/kW]
$h_{W,suunn}$	Unit cost for planned interruption in the value of year 2005 [€/kW]
I	Set of components that failure causes an outage for customer j
$JLKA\%$	Feeder-specific cabling rate
$k(l)$	Annual number of interruptions experienced by LV network l [pcs]
$KAH_{ref,k}$	The reference level of DSO's customer outage costs in the year k
$KAH_{t,k}$	Customer outage costs in the year t in the value of year k
KAH_{tot}	Outage-specific customer outage cost
$ka_{kp}(i)$	Outage duration for metering point i [h]
$ka_{mp}(i,l)$	Interruption duration experienced by LV network l caused by interruption i [h]
$KA_{odott,t}$	Customer's average annual duration of interruptions weighted by annual energies caused by unanticipated interruptions in the 1-70 network in the year t [h]
$KA_{suunn,t}$	Customer's average annual duration of interruptions weighted by annual energies caused by planned interruptions in the 1-70 network in the year t [h]
KHI_{2004}	Consumer price index in the year 2004
KHI_{k-1}	Consumer price index in the year k-1
$KM_{odott,t}$	Customer's average annual number of interruptions weighted by annual energies caused by unanticipated interruptions in the 1-70 network in the year t [pcs]
$KM_{suunn,t}$	Customer's average annual number of interruptions weighted by annual energies caused by planned interruptions in the 1-70 network in the year t [pcs]
Kph	Total interruption time of metering points
Kpk	Total number of metering points affected by interruptions
LT_i	Techno-economic lifetime of the network component i
m	Number of LV networks [pcs]
mp	Total number of LV networks in the distribution area [pcs]
Mpe	Total energy of LV networks affected by interruption
Mph	Total interruption time of LV networks
Mpk	Total number of LV networks affected by interruptions
$mpk(i)$	Number of LV networks that experienced interruption i [pcs]
$mpk(i,j)$	Number of LV networks that experienced interruption duration $h(i,j)$ [pcs]
n	Number of interruptions [pcs]
N_j	Number of customers j served for the area i

$NPV_{t,i}$	Net present value of the network component *i* in the year *t*
N_T	Total number of customers served for the area
$N_{t,ec}$	Excluded customers according to Finnish Electricity Market Act
P_j	Average outage power [kW]
PJK_t	Customer's average annual number of interruptions weighted by annual energies caused by rapid autoreclosings in the year *t* [pcs]
$P_{kp}(i)$	Outage power for metering point *i* [kW]
r_{ij}	Repair time of the faulted component or switching time required to isolate the faulted component and restore the supply [h] or interruption duration for customers *j* of the area caused by outages *i*
r_j	Average annual outage duration *r* per fault for customer *j*
$RV_{t,i}$	Replacement value of the network component *i* in the year *t*
T	Length of the planning period
t_{ij}	Outage time for customer *j* caused by a failure of the component *i* [h]
T_t	Total number of hours in the year *t* (8760 h)
U_j	Average outage time per year for customer *j*
W_k	Annual supplied energy in the year *k* [kWh/a]
$W_{mp}(l)$	Annual energy of the LV network *l* [MWh]
W_t	Annual distributed energy to customers from the DSO's 0.4 kV and 1-70 kV networks in the year *t* [kWh] or annual supplied energy in the year *t* [kWh/a]
W_{tot}	Annual distributed energy of the distribution area [MWh]
x	Different interruption durations of each interruptions [h]
$\lambda_{AR,ij}$	Momentary outage frequency *i* due to autoreclosings which affects to customers *j* of the area
λ_i	Annual failure rate of the component *i* [pcs]
λ_{ij}	Failure rate of the area *i* which affects to customers *j*
λ_j	Average annual outage frequency for customer *j*

ABBREVIATIONS

ABB	Asea Brown Boveri
ACSR	Aluminium-conductor steel-reinforced
AMR	Automated Meter Reading
API	Application Programming Interface
ASAI	The Average Service Availability Index
BUC	Back-up Connection
CAIDI	Customer Average Interruption Duration Index
CELID	Customers Experiencing Long Interruption Durations
CIS	Customer Information System
CLC	CORINE Land Cover
CORINE	Coordination of Information on the Environment

CR	Cabling Rate
CSV	Comma-separated Values
DAR	Delayed Autoreclosing
DBMS	Database Management System
DBS	Database System
DMS	Distribution Management Systems
DMS600	ABB MicroSCADA Pro DMS600
DMS600 NE	ABB MicroSCADA Pro DMS600 Network Editor
DMS600 WS	ABB MicroSCADA Pro DMS600 Workstation
DRR	Distribution Reliability Requirements
DSN	Data Source Name
DSO	Distribution System Operator
ENS	Energy Not Supplied
Esri	Environmental Systems Research Institute
ET	Energiateollisuus ry, Finnish Energy Industries
ETRS	European Terrestrial Reference System
FP	Feature Pack
GeoTIFF	Geographic Tagged Image File Format
GIS	Geographical Information System
GUI	Graphical User Interface
HF	Hotfix
HV	High Voltage
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
KAH	Keskeytyksestä aiheutunut haitta, Customer Outage Cost
KSAT	Koillis-Satakunnan Sähkö Oy
LSOY	Leppäkosken Sähkö Oy
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MDP	Major Disturbance Proof
Metla	Metsäntutkimuslaitos, Finnish Forest Research Institute
MML	Maanmittauslaitos, National Land Survey of Finland's
MS	Microsoft
MSSQL	Microsoft SQL Server
MV	Medium Voltage
NCC	Network Control Center
NDE	Non-Distributed Energy
NIS	Network Information System
NPV	Net Present Value
NTPA	Not Town Plan Area
ODBC	Open Database Connectivity
OSS	Oulun Seudun Sähkö Oy
RAR	Rapid Autoreclosing
RDL	Report Definition Language
RV	Replacement Value
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQL	Structured Query Language

SSRS	SQL Server Reporting Services
SYKE	Suomen ympäristökeskus, Finnish Environment Institute
SYS600	ABB MicroSCADA Pro SYS600 Control System
TM	Transverse Mercator
TPA	Town Plan Area
TSO	Transmission System Operator
TUT	Tampere University of Technology
URL	Uniform Resource Locator
XML	Extensible Markup Language

1. INTRODUCTION

1.1 Background of the Thesis

Electricity distribution business in Finland was liberated in 1995. Due to natural monopoly nature, distribution business is regulated and supervised by regulator; Finnish Energy Authority. Supervision is practically carried out by gathering technical and economic data and key figures from Distribution System Operators (DSO).

Finnish DSOs are obligated to report detailed data of their outages and network assets to the Energy Authority and Finnish Energy Industries (ET) annually. Energy Authority's and ET's reporting requirements increase and tighten continuously, hence DSOs are demanded to gather more and more accurate data from their distribution network. DSOs typically use information systems for the distribution network management, such as Distribution Management Systems (DMS) and Network Information Systems (NIS). These information systems with their databases and stored data usually provide advanced tools to produce required reports for authority.

New Electricity Market Act was initiated due to long electricity distribution interruptions caused by storms and major weather events in summer 2010 and winter 2011-2012. New law came into effect on 1st September 2013 and according to it, fault in the distribution network caused by storm or snow load cannot cause an interruption over six hours in town plan area and over 36 hours in the other area. Due to new law, DSOs are required to prepare distribution network development plans describing the actions to fulfill the set requirements. In addition to Energy Authority's new distribution network development plan requirement, also ET requires more detailed outage data from DSOs onwards 2015.

1.2 Research Problem and Objectives

Due to constantly increasing and tightening reporting requirements, ABB MicroSCADA Pro DMS600 (DMS600) software needs development to produce the demanded information and reports from DSOs' distribution networks according to new requirements. Reporting functionalities in DMS600 software are implemented using Microsoft's SQL Reporting Services.

The objectives of the thesis are to develop methods to gather the data required in Energy Authority's and ET's reports and study different background map materials that can be utilized in reporting and be brought to DMS600 system as well as collect all important reporting requirements into one document.

The thesis introduces all relevant requirements in NIS and DMS viewpoint and defines the development needs to DMS600 software and presents developed solutions and methods.

1.3 Research Methodology

The research methodology is based on literature study and interviews with the representatives of Energy Authority and DSOs. Electricity supply system, network planning and operation processes as well as reliability analysis and economic regulation of the distribution business are presented based on literature. Energy Authority's and ET's reporting requirements are introduced based on published decrees and instructions. Development needs to DMS600 software as well as developed solutions and methods are mainly based on interviews with the DSOs' representatives.

1.3.1 Interviews

Representatives of Energy Authority and three Finnish DSOs were interviewed during the spring 2014. Energy Authority's representatives, Tarvo Siukola and Riku Kettu, were interviewed to get information of the background, reasons and objectives of the new Electricity Market Act and new reporting requirements. Also correctives to new and existing requirements were asked. Interviewed DSOs and their representatives were:

- Markku Pouttu and Arttu Ahonen from Koillis-Satakunnan Sähkö Oy
- Matti Virtanen, Tero Salonen, Ari Kartaslammi and Jouni Puikko from Leppäkosken Sähkö Oy
- Risto Pirinen, Pasi Jokinen, Jouni Perälä and Timo Patana from Oulun Seudun Sähkö

Table 1 presents the key figures of interviewed DSOs from 2013. As seen from the table; all interviewed companies are middle-sized rural area distribution companies.

Table 1. Key figures of interviewed DSOs. [Lep14, Oul14, Koi14]

	LSOY	KSAT	OSS
Eletricity transmission	378.6 GWh	171.9 GWh	447.0 GWh
Peak power	87.7 MW	43.96 MW	*INA*
Length of the electricity network			
110 kV	-	-	16 km
45 kV	-	37 km	-
20 kV	1 459 km	1 587 km	1 392 km
0.4 kV	2 829 km	2 286 km	2 058 km
Number of primary substations	8	8	12
Customers	28 599	16 019	28 857
Emloyees	65	50	51

DSOs' opinions on the new Electricity Market Act and new requirements as well as network planning strategies to fulfill the set requirements were gained through interviews. Main theme in the discussions was development needs to DMS600 software according to new requirements. Methods to model and analyze the distribution reliability requirements fulfillment as well as open data utilization in DMS600 were also covered. Results of the interviews are used as a basis in the developed solutions presented in Chapter 8.

Questionnaire forms for Energy Authority and DSOs are presented in Appendix A and Appendix B.

1.4 Structure of the Thesis

The thesis contains nine Chapters. Chapter 2 covers the structure of the electricity supply system and distribution automation as well as the distribution network planning and operation processes. Chapter 2 also introduces most commonly used reliability indices and the basis of the reliability analysis theory of the distribution system.

Finnish distribution network regulator, Energy Authority, regulatory periods and regulation methods as well as new Electricity Market Act with the most important articles from the thesis viewpoint are dealt in Chapter 3. Chapters 4 and 5 cover DSOs' outage and network asset reporting requirements; reporting requirements for Energy Authority are dealt in Chapter 4 and reporting requirements for ET are presented in Chapter 5 in turn.

Chapter 6 introduces the Network Information System and Distribution Management System of the ABB MicroSCADA Pro DMS600 software with their functionalities as well as used database solutions. Also the reporting tool; DMS600 Reporting Services as well as implemented reports for Energy Authority and Finnish Energy Industries are presented.

Development needs to ABB MicroSCADA Pro DMS600 software from the Energy Authority’s and Finnish Energy Industries’ reporting requirements point of view are dealt in Chapter 7. Developed solutions and methods to DMS600 software are covered in Chapter 8.

Finally the conclusion is presented in Chapter 9.

2. ELECTRICITY DISTRIBUTION SYSTEM MANAGEMENT

2.1 The Electricity Supply System

All consumers and power plants are connected to the same power system in Finland which covers almost 100 % of the households. Power system consists of power generation, transmission network, high voltage (HV), medium voltage (MV) and low voltage (LV) distribution networks as well as consumers. [Elo11]

Transmission network consists of substations (400/110 kV and 220/110 kV), HV network (400 kV and 220 kV) and the most essential and meshed parts of the HV distribution network (110 kV). Characters of the transmission network are meshed topology, transmission in a good efficiency and long transmission distances. Transmission system operator (TSO) in Finland is Fingrid Oyj which responsibility is to monitor, operate and maintain the transmission network as well as manage the electricity transmission. According to the Finnish Electricity Market Act, Fingrid Oyj has transmission system administrator's rights and duties. [Elo11]

Distribution network consists of HV distribution networks (110 kV), primary substations (110/20 kV), MV network (mainly 20 kV in Finland), distribution substations (20/0.4 kV) and LV networks (0.1 kV and 0.4 kV). The purpose of the electricity distribution network is to supply the generated electricity from the power plants and transmission network to consumers. [Lak08]

MV network is today mostly built meshed but usually operated radially by open remote or manually controlled disconnectors. Meshed structure improves reliability in fault situations and maintenance tasks, providing back-up connection from other feeder. Thanks to radial use of the distribution network, short-circuit currents are lower, feeder protection and voltage regulation is simpler to implement and fault isolation is easier comparing to meshed network topology. LV networks in turn are usually built and always operated radially. [Lak08] Structure of the electricity supply system with different sub-systems and typical voltage levels in Finland are illustrated in Figure 1.

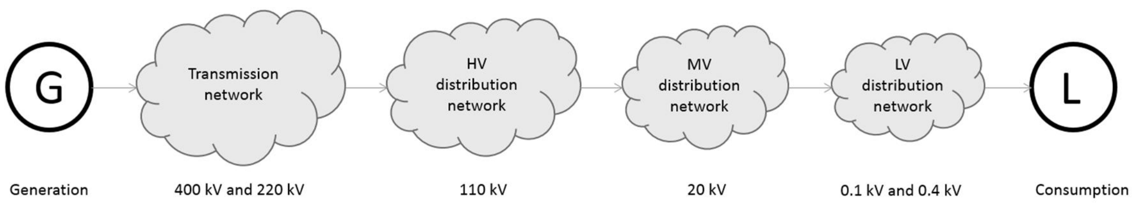


Figure 1. Structure of the electricity supply system.

In addition to the primary system of the distribution network, also secondary system and information systems are crucial part of distribution system and its management. Secondary system contains e.g. feeder protection by IEDs (Intelligent Electronic Device), remote control system, communication and data transfer. Typically used information systems in distribution management are SCADA (Supervisory Control and Data Acquisition) systems and Distribution Management Systems (DMS). [Ver97]

2.2 Distribution Automation

Distribution automation system is an integrated entity of different applications and systems which enables DSO's operative personnel to control and manage the distribution network. Distribution automation consists of five different levels of automation applications; utility level, network control center (NCC) level, substation level, feeder level and customer level. [ABB00]

In utility level, distribution system operators (DSO) utilize Network Information Systems (NIS) for network planning, calculations and analysis, documentation and network information management as well as statistics and reporting. Also Customer Information Systems (CIS) that are integrated with NIS are used for customer information management and billing functions.

In NCCs, SCADA and DMS systems are widely used to support the network operation process. SCADA systems are utilized for supervising and controlling substations and remotely controlled disconnector stations. DMS in turn provides geographical network presentation and wider distribution network management functions i.e. fault location and switching planning functions. DMS and SCADA systems are usually tightly integrated and with this compact package e.g. fault management and reporting are made easy. [Lak08]

Feeder protection, current and voltage measuring by IEDs as well as voltage regulation by on-load tap changers belong to substation automation. Also local automation in and local SCADA systems in substations are part of substation automation. [Lak08] Data transfer and communication from substations and other remote controlled switching devices to NCC is managed by means of Remote Terminal Units (RTU)

Feeder automation contains disconnector automation and network reclosers, remotely monitored fault indicators together with data transfer to NCC. Fault indication can be implemented using traditional measurements or sensors, e.g. Rogowski coils and capacitive voltage dividers. Distribution substation automation (or secondary substation automation) is also part of the feeder automation. Distribution substation automation includes e.g. transformer condition and oil temperature monitoring, LV measurements as well as fault indication functions. [Ver14]

Customer automation consists of automated meter reading (AMR), load shedding, tariff control, power quality measuring and fault indication by means of smart meters. In utility level, customer automation functions are remote meter reading and customer billing, load control management, energy balance handling and AMR system integration to DMS and SCADA as well as customer service. [Ver14].

Distribution network and different levels of distribution automation system with their functions are shown in Figure 2.

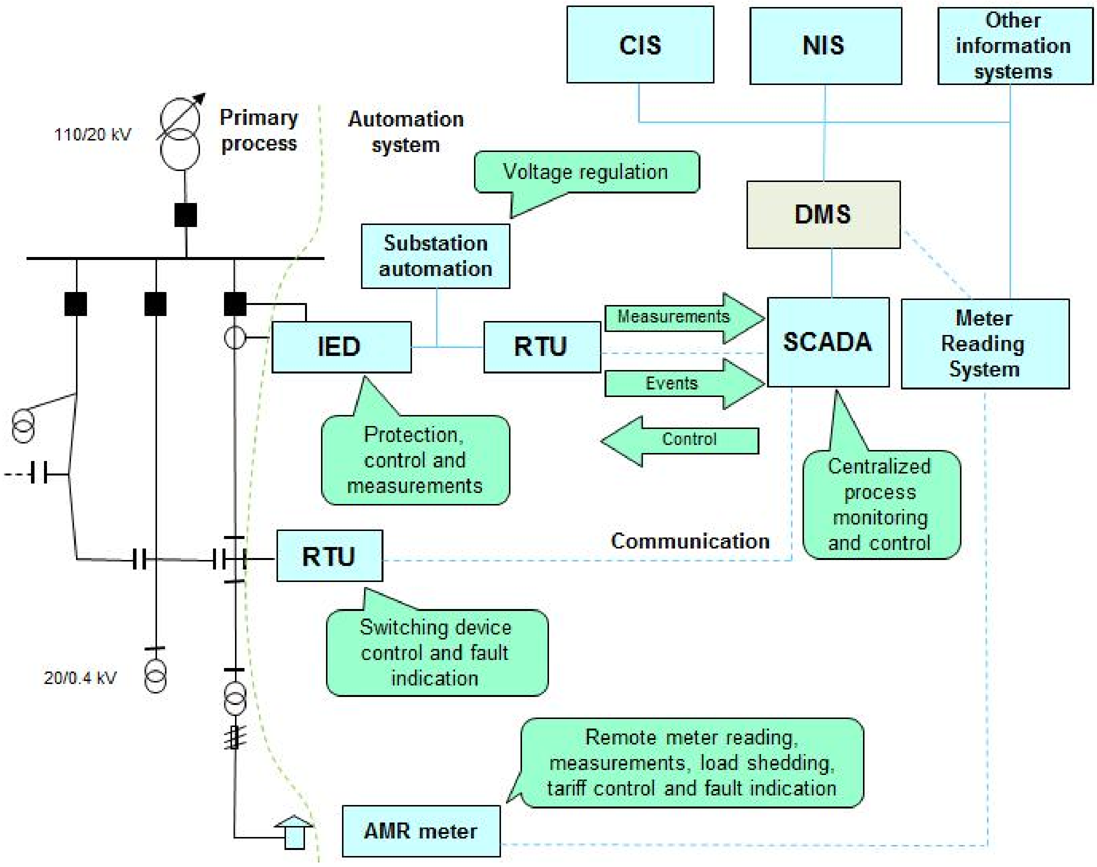


Figure 2. Distribution network and different levels of distribution automation (adapted from [Ver14]).

Objective of distribution automation is to improve quality, safety and cost-effectiveness of the electricity distribution. Advantages for distribution companies are improved safety and support in every day operations, saving in labor costs and network investments. For customers advantages are shorter supply interruptions and improved service. [Ver14]

2.3 Distribution Network Planning

Electricity distribution network planning process consists of three different stages; long-term planning, network planning (or network designing) and construction design. [Lak95]

Long-term planning covers designing of major network investments and determinations of the network development methods for the future. Aim of the long-term network planning is to define needed network investments and actions as well as design their timing to obtain optimal distribution network. [Lak95]

Network planning consists of designing of the individual investment in near future and its objective is to determine the structure of the investment. [Lak08]

Construction design in turn contains dimensioning and structural designing of individual component in the network plan. [Lak95]

The objective of distribution network planning process in each and every planning stage is to plan network which is economical by its total costs. Total costs consist of investment, operational, failure and maintenance costs. [Lak08] Distribution network planning is techno-economical optimization problem and the minimized function $F(t)$ is presented in Equation (1).

$$F(t) = min \sum_{t=0}^{T} \left(C_i(t) + C_o(t) + C_f(t) + C_m(t) \right) \quad (1)$$

where

T	Length of the planning period
$C_i(t)$	Investment costs
$C_o(t)$	Operational costs (including power losses, labor, stores and equipment)
$C_f(t)$	Failure costs
$C_m(t)$	Maintenance costs

In addition to the economic aspect of planning, designed network must also meet safety and power quality requirements, e.g. voltage drop have to stay at an acceptable level, thermal and short-circuit capacity of the conductors can't be exceeded and relay protection have to function correctly. [Lak08]

Distribution network planning period can be up to 20–30 years and techno-economic lifetimes of network components are 20–50 years. Network investments are strongly dependent from each other, thus distribution network has to be continuously developed as an entity, containing HV, MV and LV networks. Distribution network planning is ongoing process which starts over again when previous planning period is passed. Hence strategic development and proactive network planning are of great importance. [Lak08]

2.3.1 Network Information System

In distribution network planning the most important tool is Network Information System (NIS) with its planning and network analysis functionalities, saved network information and background maps. NIS is usually relational database-based software application with graphical user interface (GUI) and geographical network view. NIS and its database include information about network components, like technical and maintenance data as well as location information. NIS consists of database with stored data, database management system (DBMS) and different applications exploiting the database. [Lak08]

Data stored in NIS's database can be used in network planning as well as in network analysis like load flow and fault current calculations. NIS is also used in documentation, map printing, reporting and compilation of statistics on network assets. [Lak08] In addition, NIS often includes reliability analysis and asset management functionalities depending on the vendor. Usually NIS's static network model is used in DMS, forming the backbone of the system integration.

2.4 Distribution Network Operation

Distribution network operation basically means daily switching and control operations of the distribution network. [Lak08] The objective of the network operation is to distribute high-quality electricity safely and minimize the total costs subject of the network. [Ver97] Main functions of the distribution network operation are switching state monitoring, topology and fault management as well as switching planning. [Lak08]

Distribution network is remotely operated from the DSO's NCC; hence information systems as well as data transfer and communication are essential part of operation process. The most common information systems used in NCC are SCADA and DMS systems and they are used to ease and support the operations. [Lak08]

Substation automation and feeder automation are lifeblood for network operation process. Automation functionalities and remote control system enable network monitoring and controlling remotely from the NCC. LV network automation solutions are rare comparing to the scale of MV network automation applications. LV network automation is practically limited to the AMR meter functionalities such as remote meter reading, load shedding and fault indication. [Lak08]

2.4.1 SCADA

SCADA (Supervisory Control and Data Acquisition) system is an information system which is used for monitoring and controlling remote controlled switching components of the network. SCADA system is used in DSO's NCC and it serves real-time process data from the network like alarms, status indications, current and voltage measurements as well as fault information and event data. [Lak08] SCADA systems typically provide tools for remote relay configurations and in addition, also power quality monitoring and optimization is usually possible by means of IEDs.

SCADA system consists of redundant server computers, application programs, database and GUI as well as connections to the other information systems, e.g. DMS. SCADA's GUI consists of schematic substation and remote controlled disconnector station pictures. Geographical network presentation isn't typically available neither detailed information from the MV and LV networks. [Lak08]

SCADA is the backbone of the NCC and provides the foundation for other information systems and their functionalities. SCADA system has to be reliable and function correctly, especially in critical situations and during major disturbances. Hence the system's power supply is usually secured with UPS devices with long operating times. [Lak08]

2.4.2 Distribution Management System

Distribution Management System (DMS) is a software entity which integrates NIS and SCADA system and expands SCADA system's simple monitoring and control functions by geographical network view. DMS includes various numbers of different analysis and inference functions and it's designed to support the network operation process. [Lak08]

The foundation of the DMS is real-time information from the distribution network such as switching device's status information as well as current and voltage measurements received via SCADA. Real-time information is integrated with detailed network and customer information from the NIS. This system integration provides possibility to switching state monitoring, operations planning and fault management. The implementation of these DMS functionalities needs different kinds of static and dynamic network models from different information sources as well as topology analysis, load flow, fault current and outage cost calculation algorithms that are available for different applications. [Lak08]

Switching state monitoring is handled with the help of topology management, real-time calculations and analysis as well as field crew management functions of DMS. [Lak08]

Network operations planning can be carried out utilizing outage planning, network reconfiguration and voltage optimization applications. Also operational simulations and load estimation functions are available in DMS and can be exploited. [Lak08]

Fault management in turn, is handled using event analysis, fault location, automatic isolation and distribution restoration as well as back-up connection planning functions. Also fault reporting and customer service are made easy with DMS. [Lak08]

2.5 Reliability of Electricity Distribution

Reliability of electricity distribution is important for DSO's customers and plays significant role for DSO when assessing the quality of supply. Reliability of electricity distribution consists of performance and reliability of distribution network. Impaired reliability leads to increased number of interruptions from the DSO's customer's point of view. [Par10]

According to standard SFS-EN 50160, electricity supply interruption is defined as a situation where voltage at customer's connection point is less than 1 % of the contractual. Interruptions are divided in to planned and unanticipated outages. Planned outages are due to network maintenance and customers are informed in advance. Unanticipated outages are due to sustained or momentary faults in the network and they are categorized as short and long outages. Long outage is defined as a sustained interruption if its duration is more than three minutes. Short outage in turn is defined as a momentary interruption if its duration is less than three minutes. [SFS11]

Reliability can be improved by increasing the level of network maintenance or by network investments and renovations. Reliability improvement investments are for example:

- Underground cabling
- Relocating overhead lines to open space, e.g. on the fields and clear felling areas
- Use of aerial cable and overhead lines with covered conductors (PAS)
- Light modular substations
- Earth fault current compensation
- Overvoltage protection with gapless metal-oxide surge arresters
- Feeder automation, e.g. remote controlled disconnectors and reclosers

Reliability of the network can be evaluated based on fault statistics or based on calculations (reliability analysis). Fault statistics based on history are useful when assessing the effect of reliability improving investments. Calculations in turn are powerful tool when analysing and compering different reliability improving investments and improvement methods.

2.5.1 Distribution Reliability Indices

IEEE (Institute of Electrical and Electronics Engineers) has published various distribution reliability indices in standard 1366 IEEE Guide for Electric Power Distribution Reliability Indices and they are widely used all over the world. The most commonly used indices are SAIFI, SAIDI, CAIDI and MAIFI that indicate the reliability in the distribution system level and are based on the total number of customers in the DSO's distribution area. Indices are calculated over a predefined period of time which typically is a calendar year. [IEE12]

System Average Interruption Frequency Index (SAIFI) indicates the average number of sustained interruptions during a predefined period of time. Mathematically SAIFI is given in Equation (2).

$$SAIFI = \frac{\sum_i \sum_j \lambda_{ij} \cdot N_j}{\sum_j N_j} \tag{2}$$

where

λ_{ij}	Failure rate of the area *i* which affects to customers *j*
N_j	Number of customers *j* served for the area *i*

System Average Interruption Duration Index (SAIDI) indicates the average total duration of sustained interruptions during a predefined period of time. SAIDI is mathematically presented in Equation (3).

$$SAIDI = \frac{\sum_i \sum_j \lambda_{ij} \cdot r_{ij} \cdot N_i}{\sum_j N_j} \tag{3}$$

where

r_{ij} Interruption duration for customers *j* of the area caused by outages *i*

Customer Average Interruption Duration Index (CAIDI) indicates the average duration of sustained interruptions per fault during a predefined period of time. CAIDI can be calculated by quotient of SAIDI and SAIFI like presented in Equation (4).

$$CAIDI = \frac{SAIDI}{SAIFI} \tag{4}$$

Momentary Average Interruption Frequency Index (MAIFI) indicates the average frequency of momentary interruptions that are result of the rapid or delayed autoreclosings during a predefined period of time. Mathematically MAIFI is given in Equation (5).

$$MAIFI = \frac{\sum_i \sum_j \lambda_{AR,ij} \cdot N_i}{\sum_j N_j} \tag{5}$$

where

$\lambda_{AR,ij}$ Momentary outage frequency *i* due to autoreclosings which affects to customers *j* of the area

The IEEE Guide for Electric Power Distribution Reliability Indices standard introduces also less used CELID (Customers Experiencing Long Interruption Durations) index which indicates the ratio of individual customers that experienced interruptions with durations longer than or equal to a given time. [IEE12] CELID index could be very useful when defining the distribution reliability requirements fulfillment for Energy Authority. [Hei14] The different variations of CELID index are represented in the following according to IEEE 1366 standard.

CELID-s indicates the ratio of individual customers that experienced a single interruption with the duration longer than or equal to a given time. Mathematically CELID-s is presented in Equation (6).

$$CELID - s = \frac{CN_{(k \geq S)}}{N_T} \tag{6}$$

where

$CN_{(k \geq S)}$	Total number of customers that experienced single interruption with duration longer than or equal to S hours
N_T	Total number of customers served for the area

CELID-t indicates the ratio of individual customers that experienced interruptions with the total duration longer than or equal to a given time. Mathematically this is given in Equation (7).

$$CELID - t = \frac{CN_{(k \geq T)}}{N_T} \tag{7}$$

where

$CN_{(k \geq T)}$	Total number of customers that experienced interruptions with total durations longer than or equal to T hours

2.5.2 Reliability Analysis of Distribution Network

Radially operated distribution network is a serial system which consists of lines and different components, e.g. circuit breakers, disconnectors and transformers. Hence the reliability of distribution network consists of the reliability of lines and individual network components and their synergy. Commonly used indices of quality of supply in reliability analysis are outage frequency, outage duration and the energy not supplied due to an outage and its cost. These mentioned indices are mathematically presented in the following. [Lak95].

The average annual outage frequency λ for customer *j* can be calculated using Equation (8).

$$\lambda_j = \sum_{i \in I} \lambda_i \tag{8}$$

where

λ_i	Annual failure rate of the component *i* [pcs]
I	Set of components that failure causes an outage for customer *j*

The average outage time *U* in hours per year for customer *j* is presented in Equation (9).

$$U_j = \sum_{i \in I} \lambda_i \cdot t_{ij} \tag{9}$$

where

t_{ij} Outage time for customer *j* caused by a failure of the component *i* [h]

The average annual outage duration *r* in hours per fault for customer *j* is formulated in Equation (10).

$$r_j = \frac{U_j}{\lambda_j} \tag{10}$$

The energy not supplied (*ENS*) for customer *j* due to an outage can be calculated with Equation (11).

$$ENS_j = \lambda_j \cdot r_j \cdot P_j \tag{11}$$

where

P_j Average outage power [kW]

Reliability of the network can also be evaluated economically by calculating the costs of energy and power not supplied due to an outage. The cost benefit analysis of network investment can be carried out using the values for not supplied energy and power and comparing these to the investment cost. Unit cost values for not supplied energy and power are typically 10-100 times higher than the unit cost values for supplied energy and power, depending on customer type. [Ver14] The cost of the energy and power not supplied is mathematically formulated in Equation (12).

$$C_j = \sum_i \sum_j \lambda_{ij} \cdot a \cdot P_j + \sum_i \sum_j \lambda_{ij} \cdot r_{ij} \cdot b \cdot P_j \tag{12}$$

where

a Per-unit cost value for the power not supplied [€/kW]
b Per-unit cost value for the energy not supplied for customer *j* [€/kWh]
r_{ij} Repair time of the faulted component or switching time required to isolate the faulted component and restore the supply [h]

3. AUTHORITY REGULATION IN FINLAND

Electricity distribution in Finland, as well as in many other countries, is authority regulated regional monopoly business. Economic regulation in Finland was started in 1995, since the electricity market was liberated. The objective of the regulation is to guarantee DSOs' customers equal treatment and fair billing regardless of the identity or the location of the customer. Regulator supervises DSOs' profit and pricing levels of network services. The pricing must be reasonable and non-discriminatory and simultaneously the quality of distributed electricity must meet the set requirements. According to the Finnish Electricity Market Act, DSOs have to develop and maintain the distribution networks according to customer's needs and provide high-quality electricity. [Par13] Incentive for network development is served in the regulation model; better power quality and distribution reliability provide possibility for bigger profit.

The economic regulation was started because of the DSOs' regional monopoly positions and the lack of natural competition in electricity distribution business. Without competition there is no pressure for DSOs to develop their networks and services or operate cost-efficiently and keep the pricing reasonable. Before the electricity market was opened to competition, DSOs were mainly municipally-owned and their main objective was to provide electricity and services to the residents, not the profit maximization. Today's monopoly positions and business environment enable the possibility to maximize the profit and nowadays few Finnish DSOs' owners' objective is the profit maximization. On the other hand, most of the Finnish DSOs only take the allowed reasonable return on capital defined by the authority. [Par13]

3.1 Energy Authority

Electricity distribution regulator in Finland is Energy Authority and it was established in 1995 to regulate liberated electricity market. Energy Authority is expert organization and it operates under the Ministry of Employment and the Economy (Teollisuus- ja elinkeinoministeriö, TEM). Tasks of Energy Authority in electricity market are e.g. to supervise DSOs' reasonable return on capital and pricing of the network services, compliance with the Electricity Market Act and to promote the operation of electricity market as well as gather and publish DSOs' technical and financial key figures annually. [Par13]

3.2 Regulation Methods and Regulatory Periods

Electricity distribution business has been regulated and supervised by authority since the year 1995. Between years 1995-2004 regulation was case-specific and focused on DSOs' profit supervision and carried out afterwards. Objectives of regulation were reasonable pricing and cost-efficiency and they were presented in the context of the Electricity Market Act. Actual regulation methods were developed in 1999 and they came in the law 2000. [Par13]

Since the year 2005, regulation has been carried out in regulatory periods. Each regulatory period contains its own regulation model and methods, developed on the basis of the experiences from the previous periods. Regulation models are consisted of several different regulation methods that together form the solid entity which is used to supervise e.g. the DSOs' reasonable pricing as well as the allowed revenue. The first regulatory period was 2005-2007, second regulatory period in turn was 2008-2011 and the present regulatory period covers the years 2012-2015. After the present regulatory period, next regulatory period is planned to last 8 years, between years 2016-2023. [Par13] Figure 3 illustrates the development of regulation methods in different regulatory periods.

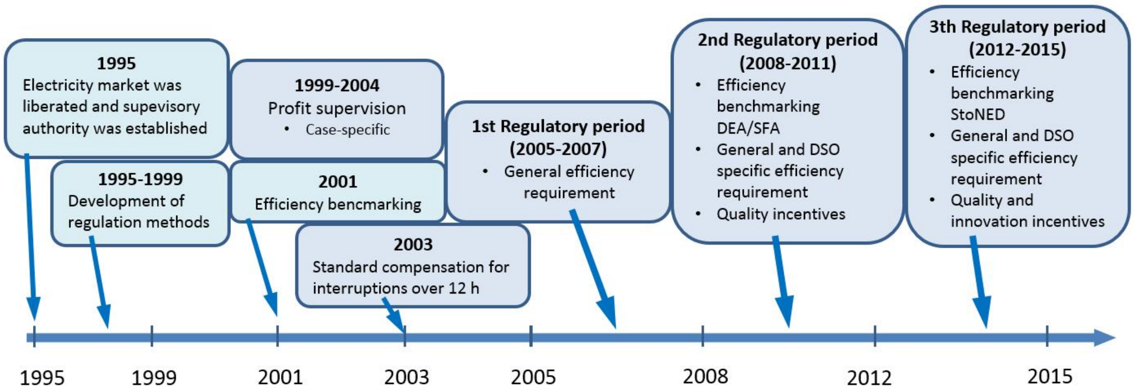


Figure 3. Development of Authority Regulation in Finland (adapted from [Par13]).

Regulation methods and models have developed during the regulatory periods but the basic idea and objective have remained the same. The objective of the development of regulation methods is to guide and support DSOs to reasonable pricing, better business development and good power quality. DSOs are also encouraged to new network investments. [EMV11a]

3.3 New Electricity Market Act

In recent years increased long electricity distribution interruptions caused by storms and major weather events, such as summer storms in 2010 and winter storms at the end of 2011, had the legislators and Energy Authority to consider tightening and amendment to Electricity Market Act and authority requirements. [Siu14] New Electricity Market Act

(588/2013) was given in 9th August 2013 and it came into effect on 1st September 2013. Objective of the new law is to improve the reliability of electricity distribution and the performance of the distribution networks and most of all to reduce the long interruptions caused by major weather events. [Siu14] New Electricity Market Act takes a stance on the maximum duration of interruptions and distribution network development. In addition, it expanded the outage compensation steps from the four-stepped to current six-stepped system.

The most important points of the new Electricity Market Act from the thesis's perspective are articles 51 §, 119 § and 52 §. The article 51 § is about the distribution reliability requirements, article 119 § is about the transition period of the distribution reliability requirements and article 52 § is about the distribution network development plans.

3.3.1 Distribution Reliability Requirements

According to article 51 §, distribution network must be planned, built and maintained so that fault in the distribution network caused by storm or snow load doesn't cause an interruption for customers with maximum duration of six hours per occurrence in the town plan area and 36 hours per occurrence in other area. Exceptions to these are customers located in the island without bridge or proper access and customers whose annual electricity consumption in last three years has been 2.5 MWh or lower and filling the reliability requirements would demand unreasonable investment costs due to distant location to other consumers. On these mentioned exceptions, DSOs can apply the requirements if the customer is located outside the town plan area. [Fin13] DSOs have to define the applied reliability requirements in the network development plans. If the applied requirements aren't described, the 36 hour time limit is used. [Ene14a] Article 119 § defines the transition periods to these reliability requirements, like presented in the next subchapter.

Customers who meet the requirements, i.e. customers who are supplied by the distribution network that meets the reliability requirements, have to be defined in advance and so that the whole feeding path from the substation to customer's connection point meets the requirements. [Siu14]

Single crossings of these set interruption time limits won't lead to sanctions but systematically frequent violations will be considered as neglect of the obligation to develop distribution network (article 19 § of the Electricity Market Act). [Ene14a]

Reason why the new act takes a stance only to interruptions caused by storm or snow load and not to all interruptions caused by any reason, is that legislator wanted to limit the number and duration of interruptions caused by storms and major weather events. [Siu14] Interruptions caused by other reasons are considered in the obligation to develop the distribution network. [Ene14a] According to the obligation, DSOs must maintain, operate and develop their distribution network and back-up connections to other DSOs' distribution networks according to set requirements and customers' reasonable needs. [Fin13]

The areas under considerations in the reliability requirements are town plan areas and not town plan areas. Shore plan areas aren't considered as a town plan area, thus the maximum interruptions duration is limited to 36 hours. According to [Siu14], the area division in town plan and not town plan areas is exact and isn't open to any interpretations. Also interviewed DSOs agreed to this with Energy Authority and this division is much easier and exact also to NIS and DMS vendors, comparing to division city, urban area and rural area.

New Electricity Market Act will have huge impact on DSOs' distribution network development strategies and network planning processes. The law doesn't take a stance on how DSOs should reach the set requirements but needless to say that the underground cabling in the MV and LV networks will increase exponentially.

3.3.2 Transition Period of Distribution Reliability Requirements

The article 119 § is about the transition period of the distribution reliability requirements (article 51 §). According to transitional provision set in new Electricity Market Act

- 50 % of DSO's customers must meet the requirements set in article 51 § at the latest by 31st December 2019 excluding holiday houses
- 75 % of DSO's customers must meet the requirements set in article 51 § at latest by 31st December 2023 excluding holiday houses
- 100 % of DSO's customers must meet the requirements set in article 51 § at latest by 31st December 2028 including holiday houses

Energy Authority may grant extra time to DSOs to meet the set reliability requirements. Extra time can be applied for the 75 % target of the year 2023 and for the 100 % target of the year 2028. Extra time maybe granted if DSO can prove that the required network development actions contain remarkable amount of underground cabling in the MV and LV voltage levels and remarkable part of distribution network have to be renovated before the end of its techno-economic lifetime. The deadline of 75 % of customers target can be postponed to 31st December 2028 and the deadline of 100 % of customers target can be postponed to 31st December 2036. DSOs have to submit the application to postpone the required deadlines by 31st December 2017 to Energy Authority. [Fin13] Authority assesses that deferments to required deadlines can theoretically be granted approximately for 20 % of 80 Finnish DSOs. [Pou14] According to interviewed DSOs, KSAT and LSOY will apply deferment to deadlines.

3.3.3 Distribution Network Development Plans

According to the article 52 § of the Electricity Market Act, DSOs must create development plans for their distribution networks starting from the year 2014. The development plan must be updated every two years. The development plan must include the detailed description of actions divided into two year periods that will improve the reliability and performance of the distribution network systematically and in the long run. By implementing the described actions, distribution network must meet requirements set in the articles 51 § and 119 §. [Fin13] DSOs' systematic network development must be seen in the development plans as well as network maintenance principles and strategies have to be taken into account. [Ene14b] Also the reliability of electricity supply for important customers from the society point of view must be taken under consideration in the plans. [Fin13]

Energy Authority have right to demand DSO to make changes to the delivered distribution network development plan within six months from the arrival. Changes are demanded if authority sees that the planned actions won't lead to the fulfillment of requirements set in the articles 51 § and 119 § or won't improve the reliability of the network systematically and in the long run. [Fin13]

4. REPORTING REQUIREMENTS FOR ENERGY AUTHORITY

During the regulatory period Energy Authority obligates DSOs annually report their figures describing the electricity distribution network activity, network asset information as well as financial key figures from the previous year. The figures describing the electricity distribution network activity contains e.g. indices of DSOs' quality of supply. Network asset reports in turn contain information about DSOs' distribution network, like length of the network and different conductors as well as number and average ages of different network components.

Required data and indices that are essential on the thesis point of view and possible to be reported utilizing DMS600 software and stored data are presented in this Chapter and dealt in the thesis. The required financial key figures as well as the figures from transmission networks, et cetera, aren't covered.

4.1 Figures Describing the Electricity Distribution Network Activity

Energy Authority requires DSOs to report figures describing the electricity distribution network activity annually. Figures must be reported to authority's web portal by the 31st May. [EMV11a] Reported figures are divided in six sections that are listed in the following:

- Nature and scope of distribution network activity
- Figures concerning the economy of distribution network activity
- Figures concerning the price of distribution network activity
- Figures describing the quality of distribution network activity
- Figures describing the quality of 110 kV distribution network activity
- Figures concerning the effectiveness of distribution network activity

Nature and scope of distribution network activity and figures describing the quality of distribution network activity are dealt in the following subchapters and the reported data is presented more precisely in details in the Appendix C.

4.1.1 Nature and Scope of Distribution Network Activity

In the nature and scope of distribution network activity section, DSOs must report e.g. the length and cabling rates of the network, number of network service points as well as number and capacity of substations and transformers in different voltage levels (0.4 kV, 1-70 kV and 110 kV). DSOs are also obligated to report the amount of transferred and received energies and powers as well as the number of DSO's own employees in the distribution network operations. [EMV12b]

4.1.2 Indices Describing the Quality of Distribution Network Activity

Energy Authority's gathered indices describing the quality of distribution network activity consist of eleven reported indices. Required indices are e.g. customer's average annual duration and number of interruptions caused by unanticipated and planned interruptions in the 1-70 kV networks. Also the number and duration of interruptions caused by rapid and delayed autoreclosings in the 1-70 kV networks as well as the total number of unanticipated interruptions in the 0.4 kV networks are reported to the authority annually. All calculated indices are weighted by DSO's annual energies. [EMV12b]

Index calculations are carried out in MV network level (1-70 kV), i.e. the interruptions in the 0.4-1 kV networks are not taken into account as well as the interruptions caused by the HV networks (over 70 kV) are also excluded from the calculations. In addition, only interruptions due to DSO's own network are reported. [EMV12b]

Mathematical equations of the indices are presented in the following according to [EMV11a]. Given Equations (13)-(16) can be applied separately for planned and unanticipated interruptions as well as for rapid and delayed autoreclosings.

Customer's average annual duration of interruptions (t) weighted by annual energies caused by unanticipated or planned interruptions in the 1–70 kV network can be calculated with Equation (13)

$$t = \frac{1}{W_{tot}} \cdot \sum_{l=1}^{m} \left\{ W_{mp}(l) \cdot \left(\sum_{i=1}^{n} ka_{mp}(i,l) \right) \right\} \tag{13}$$

where

W_{tot}	Annual distributed energy of the distribution area [MWh]
m	Number of LV networks [pcs]
n	Number of interruptions [pcs]
$W_{mp}(l)$	Annual energy of the LV network l [MWh]
$ka_{mp}(i,l)$	Interruption duration experienced by LV network l caused by interruption i [h]

Customer's average annual number of interruptions (k) weighted by annual energies caused by unanticipated or planned interruptions including delayed and rapid autoreclosings in the 1–70 kV network can be calculated using Equation (14)

$$k = \frac{1}{W_{tot}} \cdot \left\{ \sum_{l=1}^{m} \left(W_{mp}(l) \cdot k(l) \right) \right\} \tag{14}$$

where

$k(l)$	Annual number of interruptions experienced by LV network l [pcs]

Customer's average annual duration of interruptions (t) caused by planned and unanticipated interruptions including delayed autoreclosings is calculated with Equation (15)

$$t = \frac{\sum_{i=1}^{n} \sum_{j=1}^{x} mpk(i,j) \cdot h(i,j)}{mp} \tag{15}$$

where

x	Different interruption durations of each interruption [h]
$mpk(i,j)$	Number of LV networks that experienced interruption duration $h(i,j)$ [pcs]
$h(i,j)$	Interruption duration for LV networks [h]
mp	Total number of LV networks in the distribution area [pcs]

Customer's average annual number of interruptions (k) caused by planned and unanticipated interruptions including delayed autoreclosings is calculated using Equation (16)

$$k = \frac{\sum_{i=1}^{n} mpk(i)}{mp} \tag{16}$$

where

$mpk(i)$	Number of LV networks that experienced interruption i [pcs]

Presented indices describing the quality of distribution network activity are used when calculating the customer outage costs and the reference level of customer outage costs by Energy Authority annually. These calculated customer outage cost indices are used in economic regulation in the 3rd regulatory period. The role and usage of customer outage costs in regulation model as well as the mathematical formulas are presented in the following subchapter.

4.1.3 Customer Outage Costs

Calculated customer outage cost values are used in Energy Authority's regulation model, determining DSOs' efficiency bonus, quality bonus as well as the reasonable return of capital. Customer outage costs are calculated from reported outage indices and outage unit costs that are defined in the value of year 2005. Defined outage unit costs are based on study carried out by Helsinki University of Technology, TUT and several Finnish DSOs between years 2004-2005. Outage unit costs have been modified by Energy Authority to describe the harm to customer due an outage more precisely. Outage unit costs are determined for unanticipated and planned outages as well as for delayed and rapid autoreclosings. [EMV11b] Used customer outage unit costs are presented in Table 2.

Table 2. Customer outage unit costs. [EMV11b]

Unanticipated Outages		Planned Outages		DAR	RAR
$h_{E,odott}$ [€/kWh]	$h_{W,odott}$ [€/kWh]	$h_{E,suunn}$ [€/kW]	$h_{W,suun}$ [€/kWh]	h_{AJK} [€/kW]	h_{PJK} [€/kW]
11.0	1.1	6.8	0.5	1.1	0.55

Customer outage costs (KAH) in the year *t* in the value of year *k* can be calculated using Equation (17).

$$KAH_{t,k} = \begin{pmatrix} KA_{odott,t} \cdot h_{E,odott} + KM_{odott,t} \cdot h_{W,odott} + \\ KA_{suunn,t} \cdot h_{E,suunn} + KM_{suunn,t} \cdot h_{W,suunn} + \\ AJK_t \cdot h_{AJK} + PJK_t \cdot h_{PJK} \end{pmatrix} \cdot \left(\frac{W_t}{T_t}\right) \cdot \left(\frac{KHI_{k-1}}{KHI_{2004}}\right) \quad (17)$$

where

$KA_{odott,t}$	Customer's average annual duration of interruptions weighted by annual energies caused by unanticipated interruptions in the 1-70 network in the year *t* [h]
$h_{E,odott}$	Unit cost for unanticipated interruption duration in the value of year 2005 [€/kWh]
$KM_{odott,t}$	Customer's average annual number of interruptions weighted by annual energies caused by unanticipated interruptions in the 1-70 network in the year *t* [pcs]
$h_{W,odott}$	Unit cost for unanticipated interruption in the value of year 2005 [€/kW]
$KA_{suunn,t}$	Customer's average annual duration of interruptions weighted by annual energies caused by planned interruptions in the 1-70 network in the year *t* [h]
$h_{E,suunn}$	Unit cost for planned interruption duration in the value of year 2005 [€/kWh]

$KM_{suunn,t}$	Customer's average annual number of interruptions weighted by annual energies caused by planned interruptions in the 1-70 network in the year *t* [pcs]
$h_{W,suunn}$	Unit cost for planned interruption in the value of year 2005 [€/kW]
AJK_t	Customer's average annual number of interruptions weighted by annual energies caused by delayed autoreclosings in the year t [pcs]
h_{AJK}	Unit cost for delayed autoreclosings in the 1-70 network in the year *t* in the value of year 2005 [€/kW]
PJK_t	Customer's average annual number of interruptions weighted by annual energies caused by rapid autoreclosings in the year *t* [pcs]
h_{PJK}	Unit cost for rapid autoreclosings in the 1-70 kV network in the year *t* in the value of year 2005 [€/kW]
W_t	Annual distributed energy to customers from the DSO's 0.4 kV and 1-70 kV networks in the year *t* [kWh]
T_t	Total number of hours in the year *t* (8760 h)
KHI_{k-1}	Consumer price index in the year *k-1*
KHI_{2004}	Consumer price index in the year 2004

In the regulation model, DSO's quality bonus is formulated comparing DSO's present actual $KAH_{t,k}$ to DSO-specific reference level of customer outage costs (KAH_{ref}). The reference level of customer outage costs is based on DSO's historical average of customer outage costs. [EMV11b] The reference level of DSO's customer outage costs (KAH_{ref}) in the year *k* can be calculated with Equation (18).

$$KAH_{ref,k} = \frac{\sum_{t=2005}^{2010}\left[KAH_{t,k} \cdot \left(\frac{W_k}{W_t}\right)\right]}{6} \tag{18}$$

where

$KAH_{t,k}$	Actual customer outage costs in year *t* in value of year *k* [€]
W_k	Annual supplied energy in the year *k* [kWh/a]
W_t	Annual supplied energy in the year *t* [kWh/a]

According to interview [Siu14], Energy Authority will require DSOs to report outages metering point-specifically in 2-3 years like Finnish Energy Industries (Energiateollisuus ry, ET). From the 1st January 2015, ET demands metering point-specific outage reporting and customer outage cost calculations.

4.2 Network Asset Reports

During the regulatory period, Energy Authority obligates DSOs to report required information about their network assets. Required asset information from the previous year has to be reported in the Energy Authority's web portal by 31st March annually.

Required data is detailed information about DSOs' distribution network and different network components like lengths of different types of underground cables and overhead lines, number of different network components e.g. transformers, disconnectors and circuit breakers. Also number and length of demolished components and lines have to be reported as well as the replacement values (RV) and average ages of the components. Different network components and conductors must be reported according to their voltage level, type and size. Required component summaries can be produced using DMS600 Reporting Services which queries and lists the asset data dynamically from the DMS600's network database. DMS600 Reporting Services, reporting functionalities and different reports are presented in Chapter 6.

In the 3rd regulatory period, DSO's network investments have to be divided in replacement and expansion investments and the investment types must be reported by different components. Also the techno-economic lifetimes of different network components determined by DSO are required. In addition to the reported lengths of underground cables, DSOs' have to also calculate and report separately the amount of underground cables in different land type areas. Different land types are divided in four different excavation classes.

Required data in the network asset reports are presented in details in the Appendix D. The principle and background of excavation class reporting and division of network investments are clarified in the following subchapters. Also the net present value (NPV) and RV calculations of the network are covered in the following.

4.2.1 Excavation Class Calculations for Underground Cables

Replacement value (RV) of the distribution networks is calculated annually by Energy Authority, based on DSOs' asset reports. RV effects directly to the DSO's allowed return on capital and the excavation costs of underground cables form remarkable part of the RV of the network. Hence, DSOs are required to report the amount of underground cables on the different land types to the authority annually. [EMV11c] Different land types are categorized to the different excavation classes by their difficultness to excavate. Due to new Electricity Market Act and tighten electricity distribution reliability requirements, underground cabling will increase significantly in the future. Thus the excavation costs are becoming more and more remarkable part of the value of the networks.

Four different excavation classes are used; easy, regular, difficult and extremely difficult. Excavation classes are based on CLC (CORINE Land Cover) and town plan area data as well as verbal definitions. [EMV11c] Different excavation classes and CLC codes are presented in Figure 4.

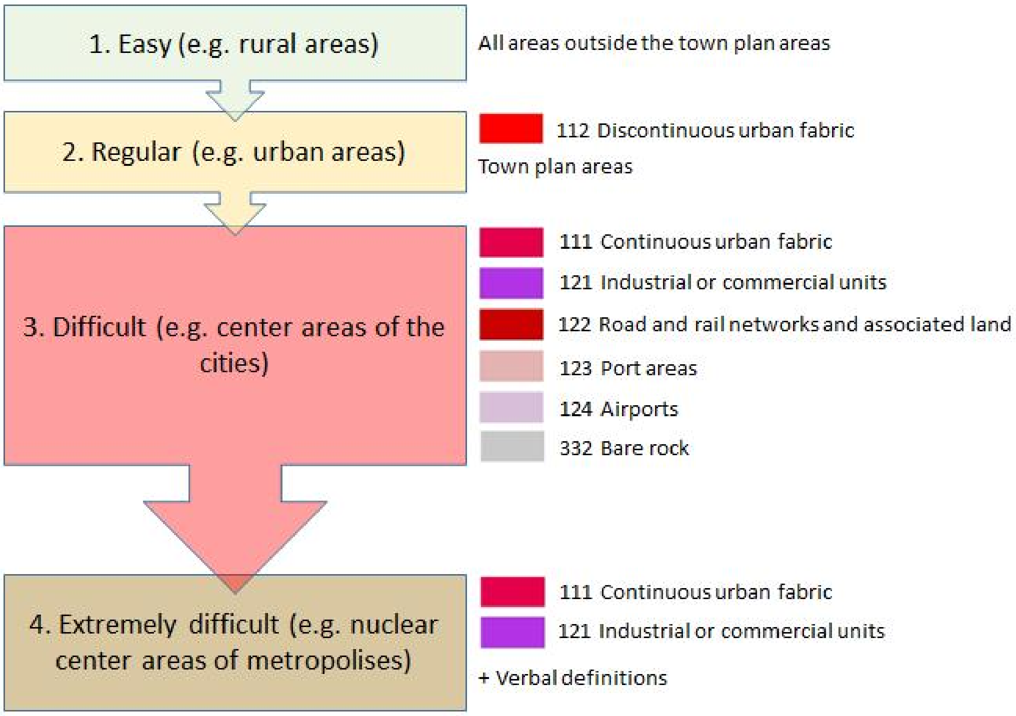


Figure 4. Excavation classes and CLC classes for underground cables (adapted from [EMV11c]).

Reported amount of underground cables in different excavation classes are changed to the length of the cable trenches by Energy Authority. Cable trench lengths are calculated with the help of trench sharing coefficients by dividing the length of the underground cables in different excavation classes by peculiar coefficients. Hence the length of the cable trench in particular class can be calculated by adding up the MV and LV cable trench lengths. [EMV11c] The trench sharing coefficients are defined by Energy Authority based on two surveys to Finnish DSOs. Trench sharing coefficients for different excavation classes are presented in Table 3.

Table 3. Trench sharing coefficients of the different excavation classes. [EMV11c]

Excavation class	**Trench sharing coefficient** $\left(\frac{Length\ of\ the\ underground\ cable}{Length\ of\ the\ cable\ trench}\right)$	
	20 kV	**0.4 kV**
Easy	1.1	1.5
Regular	1.2	1.75
Difficult	1.3	2.0
Extremely difficult	2.0	3.0

If DSO's actual cable trench lengths are known, they can be used in reporting instead of the calculated trench lengths. In that case, all trench lengths have to be reported using actual trench lengths and the coefficients can’t be used. [EMV11c] The unit costs of different excavation classes are presented in Table 4.

Table 4. Unit costs of excavation classes. [Ene14d]

Excavation Class (0.4 kV and 20 kV cables)	Unit	Unit cost [€/km]
Easy	km	10 120
Regular	km	23 110
Difficult	km	66 000
Extremely difficult	km	128 240

In the 3rd regulatory period, the amount of cables in each excavation classes has to be reported every year. Differing from the previous regulatory period, cable lengths in different classes are required to be calculated utilizing CLC data along with the verbal definitions (presented in Appendix E). [EMV11c]

CLC data includes land type information for whole Finland and is updated every five years but the latest update is from 2006, though. According to [Här14], CLC data will be updated next time in the fall of 2014 and later on the update interval will be more frequent. Even though the CLC material is from the year 2006, Energy Authority doesn’t consider it as a problem to be utilized in the calculations. According to Energy Authority, it’s more reasonable to utilize obsolete CLC data in the excavation class calculations comparing to the 2nd regulatory period, when the excavation classes were only based on verbal definitions. Excavation class calculation based on CLC data treats all DSOs more equitably and the calculations are more unequivocal. Utilizing the same material during the regulatory period makes the RV calculations of the network more continuous and predictable between different years and regulatory periods. DSOs can fix the possible errors in the data resulted from the sparse update interval. [EMV11c]

CLC data in 25 m^2 raster form must be used in the 3rd regulatory period. This reduces interpretation differences and injustice in excavation class calculations between DSOs and enables more effective authority supervision. Hence, Energy Authority can verify the reported cable amounts in different excavation classes by the DSOs more effectively. [EMV11c]

4.2.2 Division of Network Investments

In the Energy Authority’s 3rd regulatory period new network investments must be divided in expansion and replacement investments in the network asset reporting. Investments have to be divided because Energy Authority supervises DSOs’ investments annually to ensure the adequate level. Investment level is monitored e.g. in supervision of DSOs’ obligation to develop their distribution networks. [EMV12a]

Expansion investment is an investment which purpose is to connect new customers to the network and it’s meant to be financed by customers’ connection payments.

All new parts of the network that have been built to supply new service points are expansion investments. [EMV12a]

Replacement investment is an investment which replaces old network component and improves the performance of the distribution network. The purpose of replacement investment is to maintain and develop network and the investment is meant to be financed by customers' annual distribution fees. Reason for replacement investment can be the end of the lifetime of the network component, need to increase the capacity of the network or need to improve the reliability, safety or energy efficiency of the network. [EMV12a]

In addition to network asset reporting, network investments have to be divided annually in the indices of quality and profitability of the distribution network activity report, using unit prices of the network components determined by Energy Authority. [EMV11a] Network investments can't be divided or reported using present version of DMS600 NE but the functionality is already implemented to DMS600 4.4 FP1 HF1 program version, which will be released at the end of the year 2014. Developed functionality is presented in Chapter 8.

4.2.3 Net Present Value and Replacement Value of the Network

Gathered network asset information is used in the net present value (NPV) and the replacement value (RV) of the distribution network calculations by Energy Authority.

NPV of the distribution network is the main factor defining DSOs' reasonable return on capital which is regulated by the authority in the regulation model. NPV of the distribution network is calculated using average ages, lifetimes and RVs of the network components. If the age of the component is unknown, it has to be concluded from the feeding network. If the age of the feeding network is also unknown, a value on 70 % of the component's defined lifetime is used. In addition, if the age of the network component is higher than its defined techno-economic lifetime, the lifetime is used as its age. DSOs can define the lifetimes of the different of components by themselves but the lifetimes have to be chosen between the predefined values by the authority. Once the lifetime to different kind of components is chosen, it has to be used systematically during regulatory periods. NPV of the network component i in the year t can be calculated using Equation (19) when the techno-economic lifetime of the component is greater than or equal to the age of the component. [EMV11b]

$$NPV_{t,i} = \left(1 - \frac{A_{t,i}}{LT_i}\right) \cdot RV_{t,i} \tag{19}$$

where

$A_{t,i}$	Age of the network component i in the year t
LT_i	Techno-economic lifetime of the network component i
$RV_{t,i}$	Replacement value of the network component i in the year t

RV of the distribution network is calculated annually using the age of different components and unit prices, published by Energy Authority. RV of the network is used when calculating the NPV of the network, like presented in Equation (19) and DSOs' reasonable depreciations that are supervised by the Energy Authority in the regulation model. [EMV11b]

4.3 Distribution Network Development Plan and Reported Information

Distribution network development plan reports came as new reporting requirement for Energy Authority with the new Electricity Market Act in 2013. Distribution network development plans must include DSOs' strategies and detailed actions to the distribution network that will improve the reliability and performance of the distribution network systematically and in the long run. By implementing the described actions, network must meet the distribution reliability requirements set in the articles 51 § and 119 §. Actions described in the development plans must be divided into two year periods or into periods defined in the transitional provision according to the questions presented in the different sections of the development plan decree. [Ene14b]

First distribution development plans were delivered to Energy Authority by 30th June 2014. Updated development plan must be delivered to authority by 30th June 2016 and since that every two calendar years at the latest by 30th June. [Ene14b]

Distribution network development plan reporting consists of the actual network plan and required data of the DSO's distribution network, planning strategies as well as future investments, et cetera. Required data is reported in the Energy Authority's web portal and the actual development plan has to be attached in pdf-format.

Reported data is divided in five different sections and they are presented briefly in the following subchapters and more precisely in details in the Appendix F. Most of the data required in the development plans can't be reported at the present with DMS600 due to defective information model and inadequate data processing tools. Developed solutions and methods that enable the reporting are presented in details in the Chapter 8.

4.3.1 The Strategic Basis of the Distribution Network Development Plan

Section 1 of the development plan report contains eleven questions, covering DSO's strategic choices and methods for distribution network development. DSOs must describe the actions to the network to fulfill the distribution reliability requirements by the end of the year 2028, according to article 51 § of the Electricity Market Act. [Ene14b]

DSO's planning criterions and strategies as well as designed investments to fulfill the reliability requirements in the town plan and other areas are asked. Also information concerning the cooperation methods with other parties and maintenance strategies as well as fault repair resources is obligated. In addition, the consideration of important metering points from the society point of view and data concerning DSO's applied local distribution reliability requirements are also required. [Ene14b]

Data required in the section 1 isn't stored in DMS600's databases; hence DSOs need to exploit other data sources.

4.3.2 Long-term Distribution Network Development Plan to Fulfill the Distribution Reliability Requirements

In section 2 of the development plan report, DSOs are obligated to report data concerning the future investments and network maintenance. Investment and maintenance costs for HV, MV and LV networks as well as for primary and distribution substations are required to be reported according to transitional periods set in the article 119 §. Also the length of the network changed to meet the reliability requirements in MV and LV voltage levels must be reported according to transitional periods, like the number of metering points located in the town plan and other areas moved to be supplied by the network which meets the reliability requirements. In addition, the estimated cabling rates in the MV and LV networks at years 2020, 2024 and 2029 are also demanded. [Ene14c]

Required data in the section 2 can be partly be reported using DMS600 NE in principle but the method isn't very usable because of the defective database structure and imperfect data of network plans saved to the network database. Development needs to DMS600 NE are covered in Chapter 7 and developed solutions are presented in the Chapter 8.

4.3.3 Present Situation of the Distribution Network from the Aspect of Distribution Reliability Requirements

In section 3, data concerning the existing distribution network from the reliability requirements point of view is reported. DSOs are required to report the length and cabling rates of MV and LV networks as well as the length of MV and LV network that meets reliability requirements. Also the number of metering points located in the town plan and other areas as well as the number of metering points that meet the reliability requirements are reported. Subsequently, the amount of overhead lines located in the forest as well as between road and forest in MV and LV voltage levels must be reported. Only the line sections where the danger of falling trees due to storm or snow load is real, are supposed to be reported. [Ene14c]

DSOs must also deliver a geographical map of the MV network to the authority where the parts that meet the reliability requirements are highlighted, thus the whole feeding path from the substation to customer's connection point meets the reliability requirements. The map must be delivered first at 2020. [Ene14c]

Section 3 is the most essential part of the development plan report from the thesis and DMS600 point of view. Most of the required data can be reported and produced utilizing available shapefile data as well as developed tools and methods. Development needs to DMS600, developed tools and methods are presented later in Chapters 7 and 8.

4.3.4 Distribution Network Plan for Present and Next Year to Fulfill the Distribution Reliability Requirements

Section 4 covers the present and next year's network investments and actions to fulfill the set reliability requirements. Assessed investment and maintenance costs in HV, MV and LV networks as well as in primary and distribution substations to fulfill the reliability requirements are required. Also the description of actions during present and next year to fulfill the reliability requirements in town plan and other areas are reported, divided in HV network and primary substations, MV network and distribution substations and LV network. Subsequently, the amount of MV and LV networks that will be changed to meet the reliability requirements by implementing the described actions during present and next year are reported. Also the number of metering points located in the town plan and other areas moved to be supplied by the network which meets the reliability requirements are required. Lastly, cabling rates in the MV and LV networks after the described actions in present and next year are reported. [Ene14c]

Data required in section 4 can be reported in future utilizing shapefile data with developed tools and methods presented in Chapter 8, requiring that also network planning functionalities will be further developed and improved.

4.3.5 Network Investments in Past Two Years to Meet the Distribution Reliability Requirements

In section 5, the fulfillment of planned investments during past two years is supervised. DSOs are required to report the investment and maintenance costs in HV, MV and LV networks as well as in primary and distribution substations. Investments are reported in book values and only replacement investments are reported according to Energy Authority's instructions. Also the actions taken in the distribution network in town plan and other areas to meet the reliability requirements are reported as well as the length of the MV and LV networks that have been changed to meet the reliability requirements during past two years. Lastly, the number of metering points, changed to be supplied by the network that meets the reliability requirements is reported. [Ene14c] Required data can be reported utilizing the tools, methods and shapefile data covered in Chapter 8.

5. REPORTING REQUIREMENTS FOR FINNISH ENERGY INDUSTRIES

In addition to reporting for Energy Authority, also Finnish Energy Industries (ET) requires DSOs to report data about network assets and outages from the previous year. DSOs' are required to send the reports to ET by the 31^{st} March annually, ET supplies the data to Enease Oy which compiles statistics on the reported information and finally Adato Oy publishes the statistics from all Finnish DSOs.

5.1 Finnish Energy Industries

ET is industrial and labour policy organization for the Finnish energy sector and it was established in 2004. ET represents companies that produce, transmit and distribute, acquire and sell electrical energy as well as district heat and cooling or offer related services. ET is responsible for the management of collective agreements for the personnel of its member companies. ET also draws up reports and disseminates information to its member companies and cooperation members. ET is a member of the Confederation of Finnish Industries (Elinkeinoelämän keskusliitto, EK) and owns the Adato Energia Oy which is a service company that provides advices and training for its members. [ET14b]

5.2 Present Outage Reporting Model

At the present, outage information is reported to ET in MV network level using real number of customers and energies. Outages are reported by outage areas individually which ensures that the outage data can be used for multiple purposes. Also authority reporting requirements are taken into account, thus the gathered data can be used when calculating the indices for Energy Authority. [ET09]

ET gathers information about outages experienced by customers connected in LV and MV networks. Due to automation functionalities in the MV networks, reporting is focused on the MV network level. Also the fact that 90 % of the interruptions experienced by the customer in the LV network are caused by fault in the MV network supports the MV network focusing. Only the number of outages in the LV network is reported. Frames of the outage reporting begin from the primary winding of the primary transformer in the substation and end to the secondary winding of the distribution transformer. Traditionally 1-20 kV voltage levels are considered as MV network's voltages but also 1 kV and 45 kV voltages belongs to MV network in ET's reports. [ET09] Figure 5 illustrates the frames of the ET's MV outage reporting.

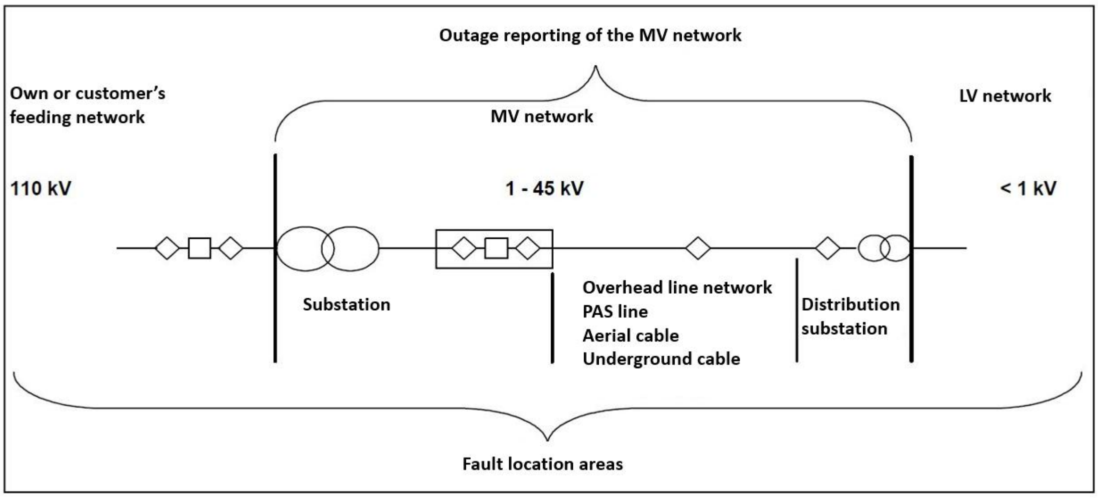


Figure 5. Frames of the present outage reporting model (adapted from [ET09]).

All interruptions experienced by customer are reported. Interruptions are divided into planned and unanticipated outages. Unanticipated outages are divided in long and short outages. Long outage is a sustained interruption with duration of over three minutes and short outage, in turn is momentary interruption with duration of less than three minutes and they are mostly autoreclosings. [ET09] Required data is filled in two separate MS Excel documents sent by ET annually. General information about distribution network assets and outages are reported to the other Excel document and detailed information of outages by outage areas is reported to other one.

5.2.1 General Information Report

In general information report, DSOs are required to report the length of the overhead lines, PAS lines, aerial cables and underground cables in the MV network, divided in the rural, urban and city areas. [ET09] Different areas are determined feeder-specifically, according to the cabling rate (CR) as follows:

- Rural area: *CR* < 30 %
- Urban area: *CR* = 30-75 %
- City: *CR* > 75 %

Feeder-specific cabling rate (*JLKA%*) can be calculated using Equation (20).

$$JLKA\% = \frac{Underground\ cable\ [km]}{Overhead\ line\ [km] + PAS\ [km] + Underground\ cable\ [km]} \tag{20}$$

Length of different conductor types must also be reported according to the MV network's earthing type. Different earthing types are:

- Neutral isolated
- Partly compensated
- Compensated

In addition, the length of different MV conductor types that are protected with RAR or/and DAR must be reported separately. [ET09]

Faults cleared by autoreclosings in MV network level must be reported as well. Total number of faults cleared, total number of metering points affected by interruptions (*Kpk*), total interruption time of LV networks (*Mph*), total number of LV networks affected by interruptions (*Mpk*) and total number of LV networks affected by interruptions weighted by LV networks' annual energies (*Empk*) are required. Data must be reported separately for RARs and DARs and divided in rural, urban and city areas and for different MV networks' earthing types mentioned earlier. [ET09]

General information report contains also network asset and LV line summary sections. In network asset summary section, total number of feeding substations, switching stations, MV feeders and metering points are required. Also the total energy of LV networks as well as the length of overhead lines and PAS lines in forest is reported. In LV asset summary, the length of overhead lines, underground cables and aerial cables as well as the total length of LV network are reported. In addition, the number of interruptions in the LV network is required to be reported divided in unanticipated and planned interruptions. [ET09]

ET's general information report with required data is presented in details in Appendix G.

5.2.2 Outage Area Report

In outage area report, DSOs are required to report the outages by outage areas so that one row in the report corresponds to one outage area of the occurred interruption. Only sustained unanticipated and planned outages are reported, the number of autoreclosings is only reported in the general information report. Interruption type, reason of interruption, fault location and fault type are reported to each interruption and they have predefined codes. Also the feeder-specific cabling rate is reported for each interruption. [ET09] Reported information and used codes in the outage area report are presented in Figure 6.

	Interruption type 3.1	Reason of interruption 3.2	Fault location 3.3	Fault type 3.4
Unanticipated interruption in the MV network	**V1** Own network **V2** Own feeding network **V3** Feeding customer network **V4** Customer network	**L1** Wind or storm **L2** Snow or ice **L3** Thunder **L4** Other weather reason **L5** Animals, birds **R1** Structural **R2** DSO's actions **T** Unknown **U1** Outsiders **U2** Force Majeure	**A1** Substation **A2** Overhead line network **A3** PAS **A4** Aerial cable **A5** Underground cable **A6** Distribution substation **A7** LV network **A8** Customer network	**VT1** Short circuit **VT2** Earth fault **VT3** Cross-country fault **VT4** Unknown
Planned interruption in the MV network	**S1** Own network **S2** Own feeding network **S3** Feeding customer network **S4** Customer network	**ST1** Line clearance **ST2** Construction **ST3** Maintenance **ST4** Load shedding		
Autoreclosings in the MV network	**J1** RAR **J1** DAR			
LV network	**P1** Fault **P2** Planned outage in LV network			

Figure 6. Reported outage information and predefined codes for ET in the present reporting model (adapted from [ET09]).

Starting and ending times and outage durations must be reported to all outage areas of each interruptions as well as the information describing the scope of the interruption. Required information consists of *Mpk*, *Mpe* (total energy of LV networks affected by interruption), *Mph*, *Kpk* and *Kph* (total interruption time of metering points) indices. [ET09] Outage area reporting requirement for ET is presented in details in Appendix H.

5.2.3 Calculated Indices by ET

ET also calculates Energy Authority's indices 17-26 for DSOs from the reported outage data. ET doesn't deliver the calculated indices directly to the authority but sends them to DSOs [ET09] when they can be examined and compared to the ones calculated by DMS and NIS. Energy Authority's indices 17-16 are presented more precisely in Appendix C and in Chapter 4.

5.3 Outage Reporting Model Onwards 2015

ET's outage reporting requirements will be renewed onwards the 1st January 2015. The most essential change, comparing to the present model, is that outages will be reported metering point-specifically. Also the area division; rural area, urban area and city will be changed to correspond to Energy Authority's area division; town plan area and not town plan area. [ET14a]

Required reports and data should be uniformed with the authority requirements. Reports should be automatically generated and produced by means of DMS and NIS systems. Metering point-specific outage reporting enables more accurate reports and better customer services. Outages in HV and LV networks are required to be reported as accurate as outages in MV networks nowadays. In addition, all interruptions in all voltage levels are demanded to be reported with outage-specific KAH values. [ET14a]

The background of the becoming requirement renovation is the attempt to improve customer services, hence the outage reporting must be metering point-specific. Interruption has the same affect to customer despite its location and the outage reason and duration should be informed to the customer regardless of the cause and occasion of the fault. [ET14a]

The purpose of the outage reporting is to gather the outage data affected to customer metering point-specifically despite the voltage level. Thus, the outage data from the unanticipated outages in the LV networks will be gathered but the planned outages won't be reported in metering point level. 110 kV and higher voltage levels are considered as HV network, 1-110 kV voltage levels belong to the MV network and LV network consists of 0.4-1 kV voltage levels in the new reporting model. Outages in the HV network are divided into own and feeding customer networks' outages. Outage reporting in the MV network begins from the primary transformer's secondary winding in the substation and ends to the secondary winding of the distribution transformer. Outages in the customer networks are suggested to be reported separately. [ET14a] Figure 7 illuminates the frames of the new outage reporting more clearly.

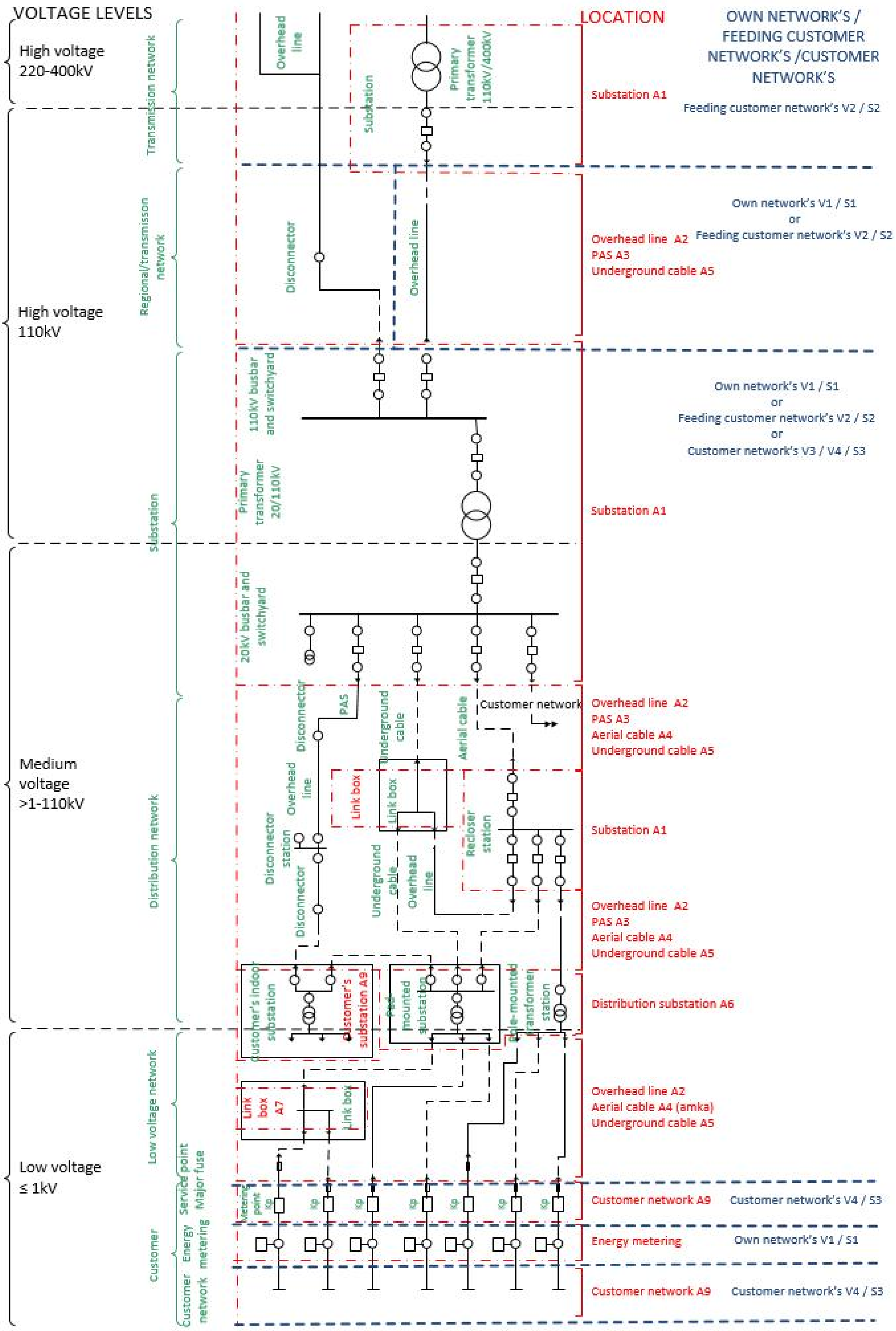


Figure 7. Frames of the new outage reporting model (adapted from [ET14a]).

All interruptions experienced by customer are reported as in the present reporting model and interruptions will be divided in to planned and unanticipated outages, like nowadays. Required data will be reported in three separate MS Excel documents onwards 2015. General information about distribution network assets as well as the outage areas will be reported almost similarly than at the present. Only the area division is changed, like discussed earlier and the division according to MV network's earthing type isn't used anymore. Also the length of the network protected as well as faults cleared by autoreclosings won't be required anymore. Neither the indices describing the quality of supply are required anymore in the general information report; only network asset data will be gathered. [ET14a]

Noteworthy is that new outage reporting model will be effective from the 1st January 2015. Hence, outage data have to be saved and analyzed using DMS according to new requirements and in new format in the year 2015. Still the outage data from year 2014 must be reported in 2015 according to the present model.

5.3.1 General Information Report Onwards 2015

In general information report, DSOs are required to report the length of the different conductor types in the HV, MV and LV networks. [ET14a]

Report still contains network asset summary section but data will be divided in town plan and not town plan areas. Total number of feeding substations, primary transformers, remote controlled disconnectors and reclosers in the distribution network, MV feeders in substations, LV networks and distribution substations are required also. Number and total annual energy of metering points in HV, MV and LV networks are reported separately. [ET14a]

ET's general information report with required data according to new reporting model is presented in details in Appendix I.

5.3.2 Outage Area Report Onwards 2015

According to the new reporting model, DSOs still report the outage areas like in the present model. In new model, outages are divided by their voltage levels (HV, MV and LV networks). Sustained unanticipated and planned outages as well as autoreclosings are reported with the information about the interruption type, reason of interruption, fault location and fault type. ET's defined codes for interruption types and reasons of interruption as well as for fault location and type have changed from the previous reporting model. [ET14a] Reported outage information and used codes according to new reporting model are presented in Figure 8.

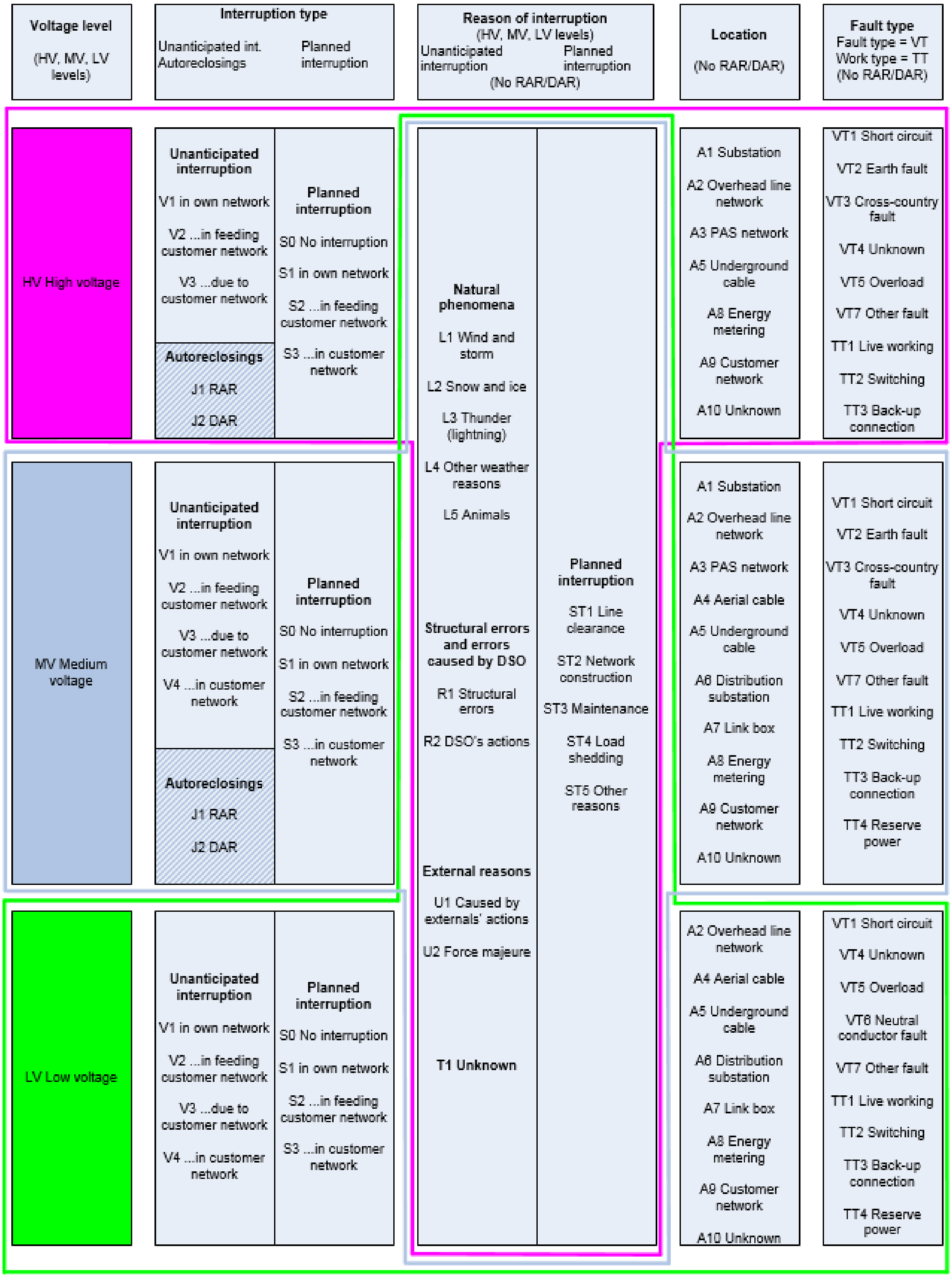


Figure 8. Required outage information and codes for ET onwards 2015 (adapted from [ET14a]).

In new outage area report, voltage level for all outage areas is required. Starting and ending times and outage durations must be reported as well as the indices describing the scope of the interruption. Reported indices are *Kpk*, *Kph* and *Kpe* (total energy of metering points affected by interruption) as well as KAH_{tot} (outage-specific customer outage cost). [ET14a]

Outage area reporting requirement for ET according to new model is presented in details in Appendix J.

5.3.3 Metering Point-specific Outage Report

In metering point-specific outage report, all interruptions experienced by metering points are reported, so that one metering point's outages during the year are reported to the same row. Metering point's code, reliability requirement class (town plan area/not town plan area) and annual energy must be reported at first. The actual outage data is filled in the feeding customer network's or own network's columns depending where the fault is occurred.

In case of unanticipated outages in the feeding customer HV or MV network, the *Ask* (total number of customers affected by interruption), *Ash* (total interruption time of customer) indices are reported for each affected metering points. In case of unanticipated and planned interruptions in own HV, MV or LV network, metering point-specific $KAH_{t,k}$ values are required in addition to *Ask* and *Ash* indices. The *Ask* index and metering point-specific $KAH_{t,k}$ values for RARs and DARs are also required. [ET14a] Metering point-specific outage report is presented in details in Appendix K.

5.3.4 Customer Outage Cost Calculation

Customer outage cost reporting is also required onwards 2015. *KAH* values must be reported outage-specifically (KAH_{tot}) as well as metering point-specifically ($KAH_{t,k}$), like discussed. KAH_{tot} will be calculated by means of DMS, based on traditional load curves or AMR measurements and $KAH_{t,k}$, in turn, will be calculated based on actual year energy. [ET14a] Metering point-specific customer outage cost is calculated similarly as for Energy Authority, applying formula presented in Equation (17).

Outage-specific customer outage cost is calculated using power and energy not supplied due to an outage metering point-specifically. [ET14a] Outage-specific customer outage cost KAH_{tot} can be calculated with Equation (21).

$$KAH_{tot} = \sum_{i=1}^{a}\left(ka_{kp}(i) \cdot h_E + h_W\right) \cdot P_{kp}(i) \cdot \left(\frac{KHI_{k-1}}{KHI_{2004}}\right) \tag{21}$$

where

a	Number of metering points that experienced interruption [pcs]
$ka_{kp}(i)$	Outage duration for metering point i [h]
h_E	Unit cost for interruption duration in the value of year 2005 [€/kWh]
h_W	Unit cost for interruption in the value of year 2005 [€/kW]
$P_{kp}(i)$	Outage power for metering point i [kW]

Outage-specific customer outage costs KAH_{tot} for entire year can be calculated by adding up all pre-calculated outage-specific KAH_{tot} values of the whole year. [ET14a]

5.3.5 Impacts and Benefits of Metering Point-specific Outage Reporting

Active state monitoring and topology management of the LV networks are required from DSOs' operative personnel in metering point-specific outage reporting. Also accurate outage reporting in the LV network level is demanded, although it might be difficult, time consuming and laborious.

Data from smart meters and meter reading systems as well as developed mobile applications for field crews might solve the problem. Customers' smart meters collect power quality and outage data from the distribution network, hence the outage times and number of interrupted customers, et cetera are saved to meter reading systems' databases and can be exploited and analyzed by SCADA and DMS systems. Mobile applications in turn can be used for LV networks' topology management and outage reporting directly from the field. Mobile applications have online access to the DMS's database; hence the LV networks' outage reporting, switching state monitoring, controlling and management eases and gets more agile.

Benefits of the new metering point-specific outage reporting for DSOs are improved customer service, more accurate outage monitoring as well as better knowledge of network maintenance and investment needs. Also comparing of storm effects eases, occupational safety improves and fault clearance accelerates. Needless to say that amount of work in utilities and NCCs certainly increases.

Impacts of ET's new requirements and metering point-specific outage reporting for DMS and NIS vendors are multifaceted. Changes in the reporting model itself poses changes and development needs to the information systems and also the transition to the new model must be implemented smoothly because two different reporting models are parallel in use. Impacts and development needs of the new requirements for DMS600 are covered later in the thesis.

6. ABB MICROSCADA PRO DMS600

MicroSCADA Pro DMS600 (DMS600) is ABB's developed information system entity for DSOs and it belongs to the MicroSCADA Pro product portfolio with SCADA system MicroSCADA Pro SYS600 (SYS600) and Compact System MicroSCADA Pro SYS600C. DMS600 system consists of Network Information System DMS600 Network Editor (DMS600 NE) and Distribution Management System DMS600 Workstation (DMS600 WS). DMS600 is used in Microsoft Windows operating systems and it's implemented by C++ programming language. [ABB12] DMS600 system architecture is shown in Figure 9.

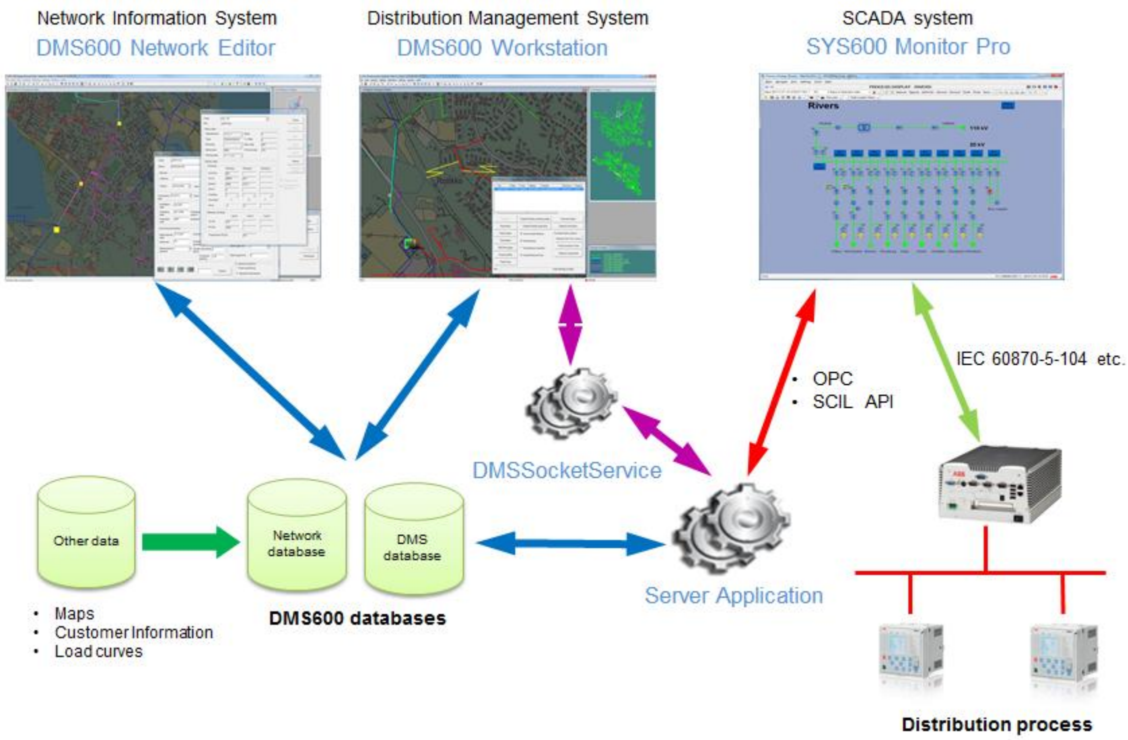


Figure 9. DMS600 system architecture (adapted from [ABB13]).

The historical roots of DMS600 are based on deceased software company Versoft Oy from Tampere, Finland, which was founded in 1985. Versoft Oy developed its own NIS (later Open++ Integra) and DMS (later Open++ Opera), which was already integrated with ABB's SCADA system. In the year 1997 ABB acquired Versoft Oy and Open++ products were supplemented with the MicroSCADA products. [Öst09]

6.1 DMS600 Network Editor

DMS600 Network Editor (DMS600 NE) is the Network Information System of the MicroSCADA Pro product portfolio. In DMS600 NE's GUI distribution network is modeled in details on geographical background maps and it integrates geographical position data and network information.

DMS600 NE is the data storage of network data. Data is saved in the network database and is available for other applications, e.g. DMS. Stored data is detailed information of the network components, like technical data, asset and maintenance information. Also network topology, i.e. connection of the line sections and different components, is saved in the network database. Customer information from the CIS is imported to the network database and is also available in DMS600 NE. Stored network data provides necessary information for network analyses e.g. load flow and short-circuit calculations. [ABB13] DMS600 NE's GUI is presented in Figure 10.

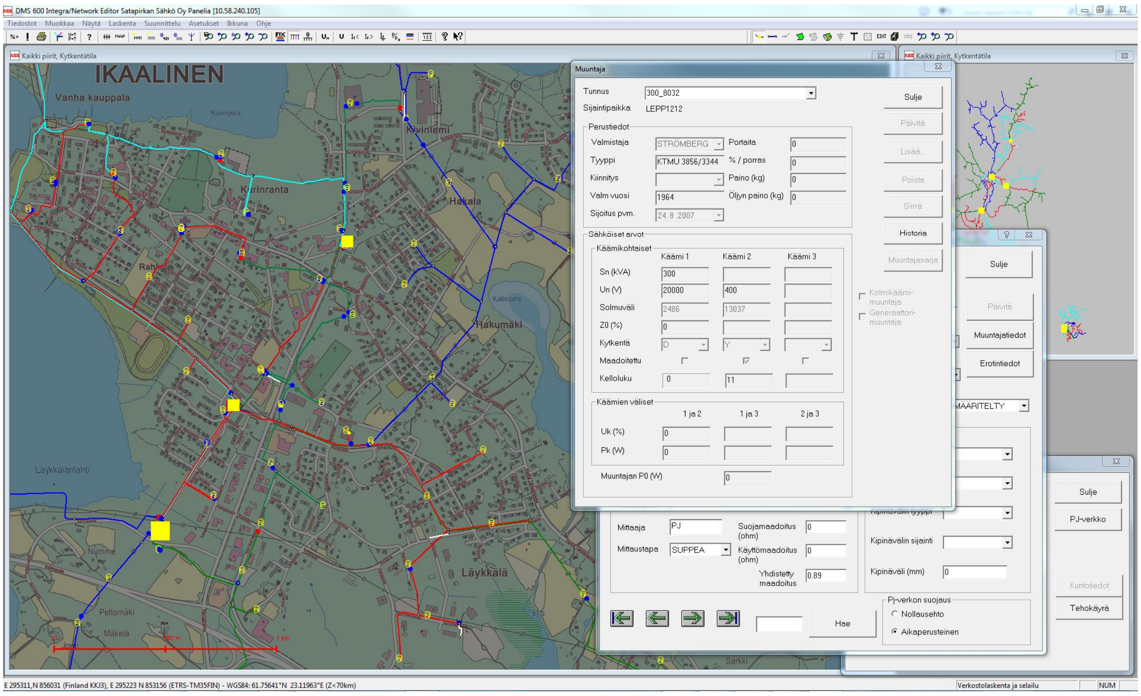


Figure 10. DMS600 NE's GUI.

DMS600 NE is designed for network editing, network information management, network planning, load flow and fault current calculations as well as relay protection and reliability analyses. Program can be used also for map printing, documentation, data analysis and network asset reporting. In addition, several administrative tasks such as SCADA integration, initializing and maintaining the background map material and symbol definitions are handled with DMS600 NE also. [ABB12] Several extension modules for network asset management and network planning, such as pole database, GPS support and offline maintenance and condition data collection and management application, are also available. [ABB13]

6.2 DMS600 Workstation

DMS600 Workstation (DMS600 WS) is geographical Distribution Management System with multiple advanced distribution network monitoring and operation functions. DMS600 WS is used in DSO's NCC with SCADA system and it helps and supports operative personnel in the decision-making. [ABB12]

DMS600 WS integrates NIS's static network model and network data from the network database with dynamic real-time process data from the SCADA system which is saved in the DMS database. DMS600 WS's GUI and fault location function are presented in Figure 11.

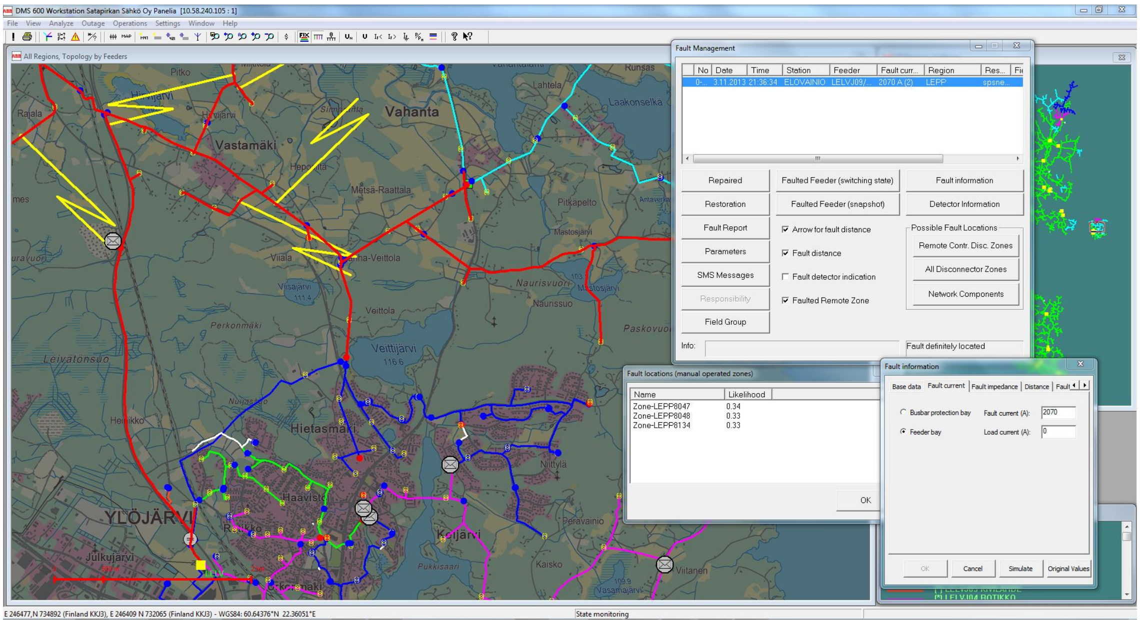


Figure 11. DMS600 WS and fault location function.

DMS600 WS is used for topology supervision and management, switching operations, fault management, operational simulations, real-time network analysis and calculations, switching planning as well as outage reporting and statistics. [ABB12]

DMS600 WS includes a large number of advanced distribution network operation functions such as automatic fault detection, isolation and distribution restoration, load estimation, Volt/VAR control and optimization as well as network reconfiguration. Also field crew management and workgroup positioning as well as customer service functionalities (e.g. Disturbance Data Form and Telephone Answering Machine) are included in the software. [ABB12]

6.3 Database Solutions

DMS600 software is built on SQL (Structured Query Language) databases. SQL databases, like all relational databases, are based on the relational model which was published by IBM researcher E.F. Codd in 1970. The relational model is based on math, predicate logic and set theory and it can be divided in three different parts: structure, maintenance and integrity. SQL is standardized language and it’s used almost in all relational database systems. [Hov12] According to the relational model, SQL database system (DBS) contains three different components; database, database management system (DBMS) and applications that exploit the database. [Lak08] DBMS provides GUI as well as different kinds of services and tools to manage the databases and saved data. DBMS includes also security, transaction recovery and data replication as well as rollback features. [Lah02] Several applications can use the same database and have access to stored data, thanks to Application Programming Interface (API) provided by DBMS and Open Database Connectivity (ODBC). [Lak08]

Typically Microsoft SQL Server (MSSQL) and databases are used in DMS600 systems but also Oracle databases are supported and can be used. MSSQL is Microsoft’s DBS and its DBMS is called Microsoft SQL Server Management Studio. In traditional DMS600 solution, two databases are commonly used, network database and DMS database. Static network information and component data such as electrotechnical data, asset and maintenance data of the network components are stored in the network database. Dynamic real-time process data from the network like fault information, status information of switching devices and measurement data are stored in the DMS database. Connection of DMS600 software to SQL databases is implemented using ODBC Data Source Name (DSN) definitions.

6.4 DMS600 Reporting Services

Stored data from the DMS600’s databases is used to produce the required outage and network asset reports for Energy Authority and ET. MS Access-based reporting tool was used for reporting measures, until DMS600 4.4 program version was released. Since the release, reporting functionalities have been implemented utilizing Microsoft SQL Server Reporting Services (SSRS).

SSRS is server-based reporting application that works within MS Visual Studio environment and enables user to create, manage, publish and deliver reports as well as extend and customize reporting functionalities. SSRS contains multiple reporting functionalities for different data sources as well as numerous ready-to-use applications that are integrated with MSSQL tools and components. [Mic14]

Most of the DMS600 users still utilize MS Access-based reporting tool and created Finnish DMS600 link database for customized reports parallel with the DMS600 Reporting Services. According to interviewed DSOs, none of them would be ready to give away the old Access-based reporting tool.

Created reports are defined as Report Definition Language (RDL) files that are XML (Extensive Markup Language) representation of the report’s formatting and embedded SQL queries. Graphical view and the SQL queries of the reports are created using the Business Intelligence Development Studio which is Visual Studio’s extension. [Kes11] Needed reports are packaged to one archive with the CreateReportPackage program and the package is installed in the DMS600 Reporting Services with the InstallReports program. [Hak13] InstallReports program is graphical easy-to-use application which is installed by the DMS600 installer. Only DSO's Reporting Services' URL and the name of the desired report package are needed to be given by the user. InstallReports program locates the DMS600 installation directory and databases, makes the required database linking and runs the necessary SQL scripts to DMS600 databases and the reporting tool is ready to use.

Reports are located in the SSRS's Report Manager website where created and installed reports can be found in separate subfolders. Figure 12 shows the DMS600 Reporting Services' web-based GUI and the report selection list of outage reports for Energy Authority and ET.

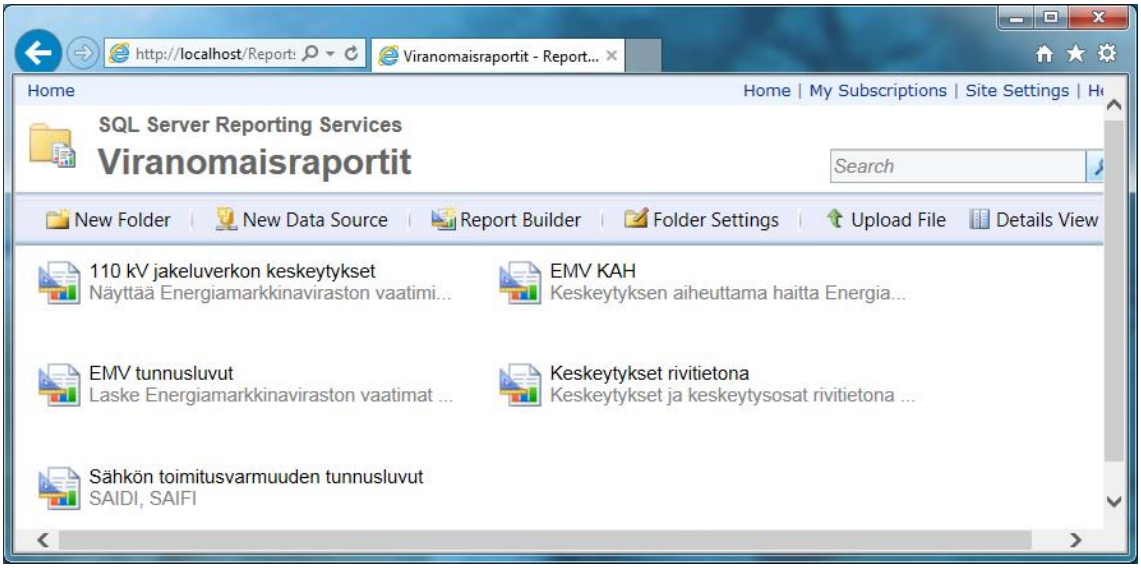


Figure 12. DMS600 Reporting Services' GUI and authority report selection list.

In the following subchapters the created reports for Finnish Energy Authority and ET are presented.

6.4.1 Reports for Energy Authority and ET

Created outage and network asset reports for Energy Authority and ET Reports are rendered in Reporting Services' GUI and they can be exported e.g. to Excel or Access database if desired.

Indices describing the distribution network activity for Energy Authority, presented in Chapter 4 and Appendix C, can be reported using Reporting Services. Also customer outage costs can be calculated with the Reporting Services. Usage is straightforward, after the desired report is selected; user is prompted with the parameter selection on the top edge of the report window. [Hak13] User gives the desired time span, DMS600's fault archive year and reporting area for the calculations. Also the customer outage cost parameters can be configured by user. An example of indices of quality of distribution network activity and customer outage costs reports for Energy Authority from the year 2013 is shown in Figure 13.

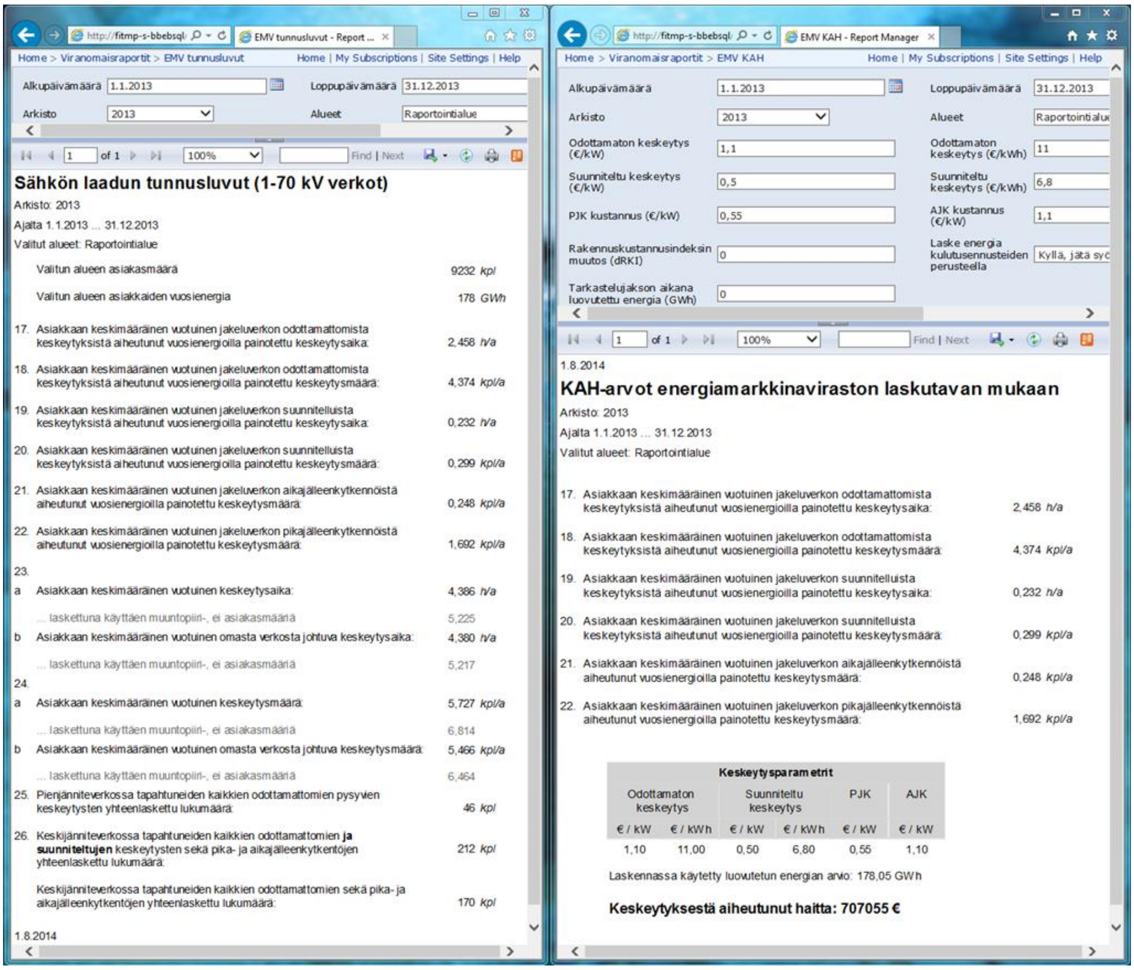


Figure 13. An example of indices of quality of distribution network activity and customer outage costs reports for Energy Authority.

Also commonly used reliability indices, such as SAIFI, SAIDI, CAIDI and MAIFI, et cetera, presented in Chapter 2, can be calculated and reported with Reporting Services, like presented in Figure 14.

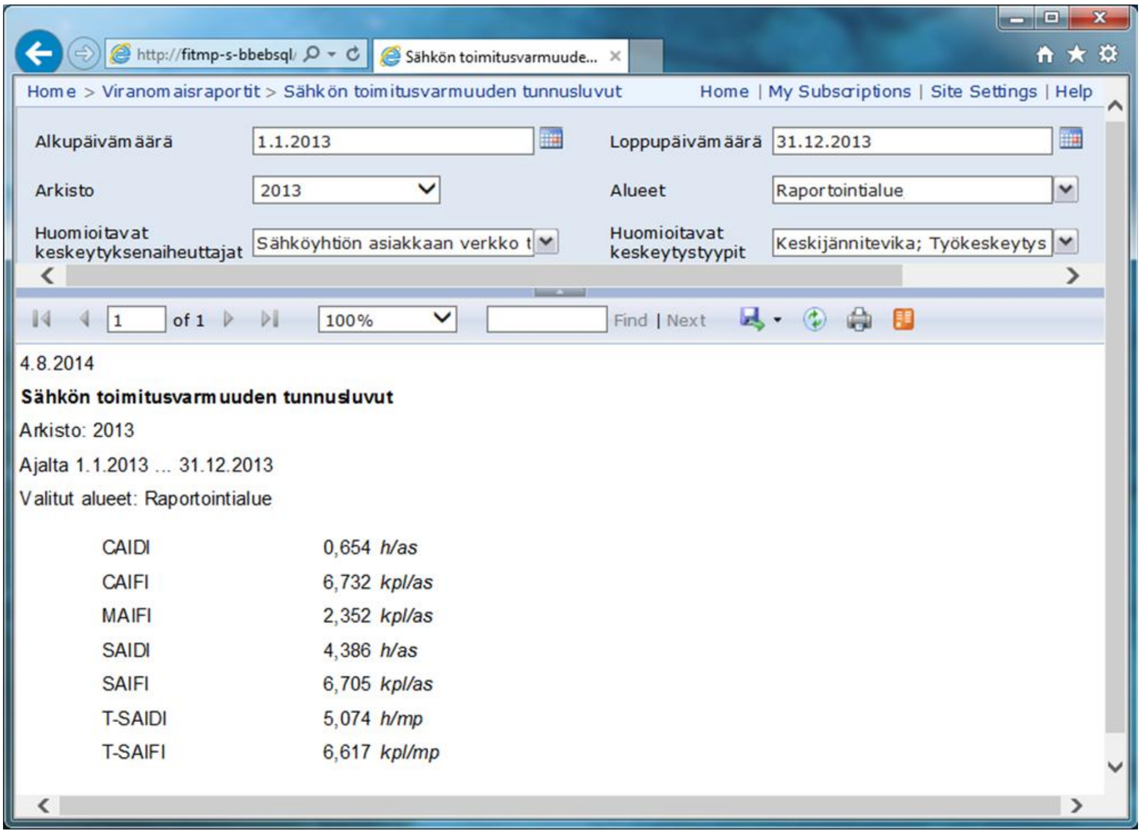


Figure 14. Calculated reliability indices.

In addition to outage reports, also network asset reports for Energy Authority, covered in Chapter 4 and Appendix D, can be produced using Reporting Services. Network asset reports are divided by different component summaries in the Reporting Service's GUI as shown in Figure 15.

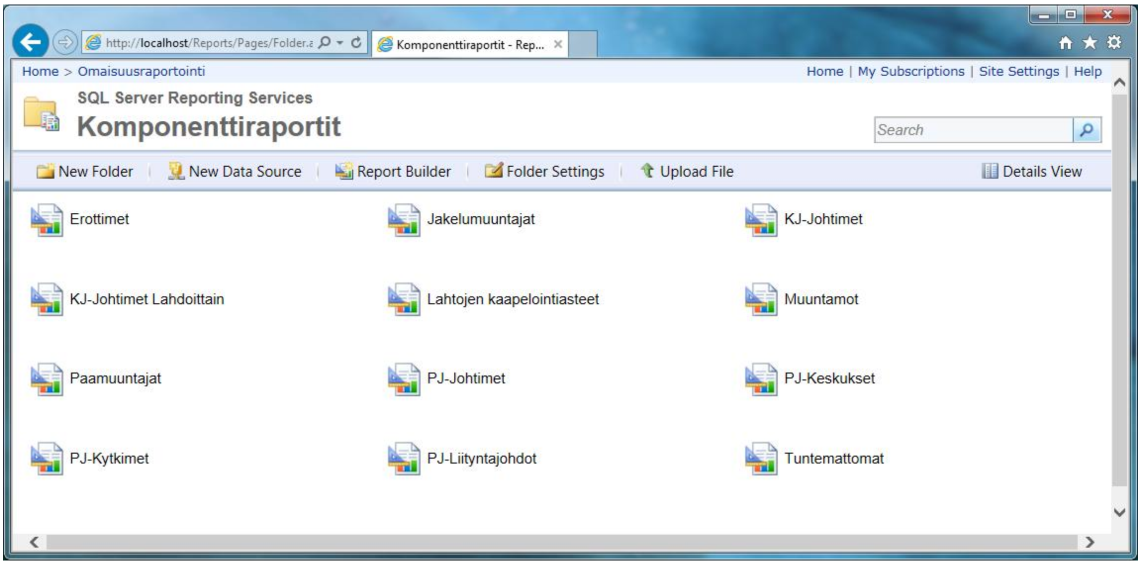


Figure 15. List of different component summary reports.

After the desired asset report is selected, user gives the installation year along with the other parameters, forming the structure of the SQL queries embedded in the reports.

Examples of MV conductor and distribution substation summary reports are given in Figure 16.

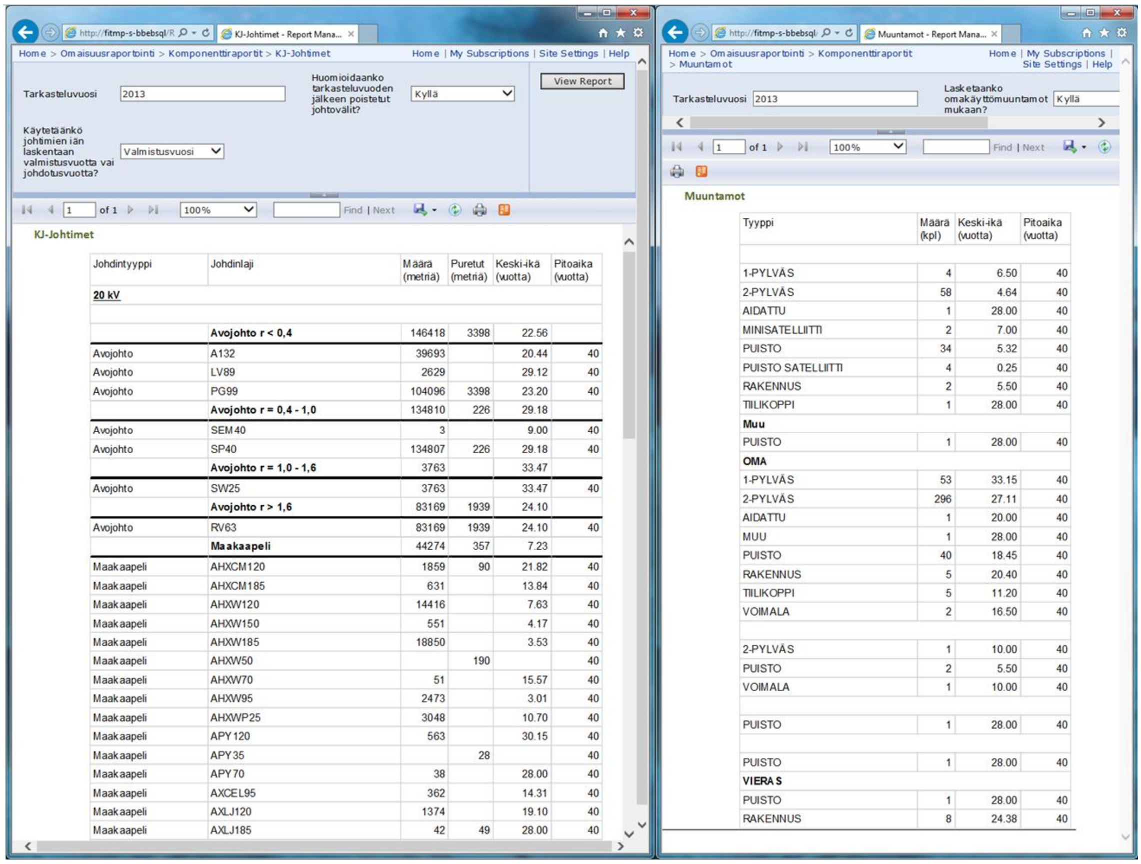
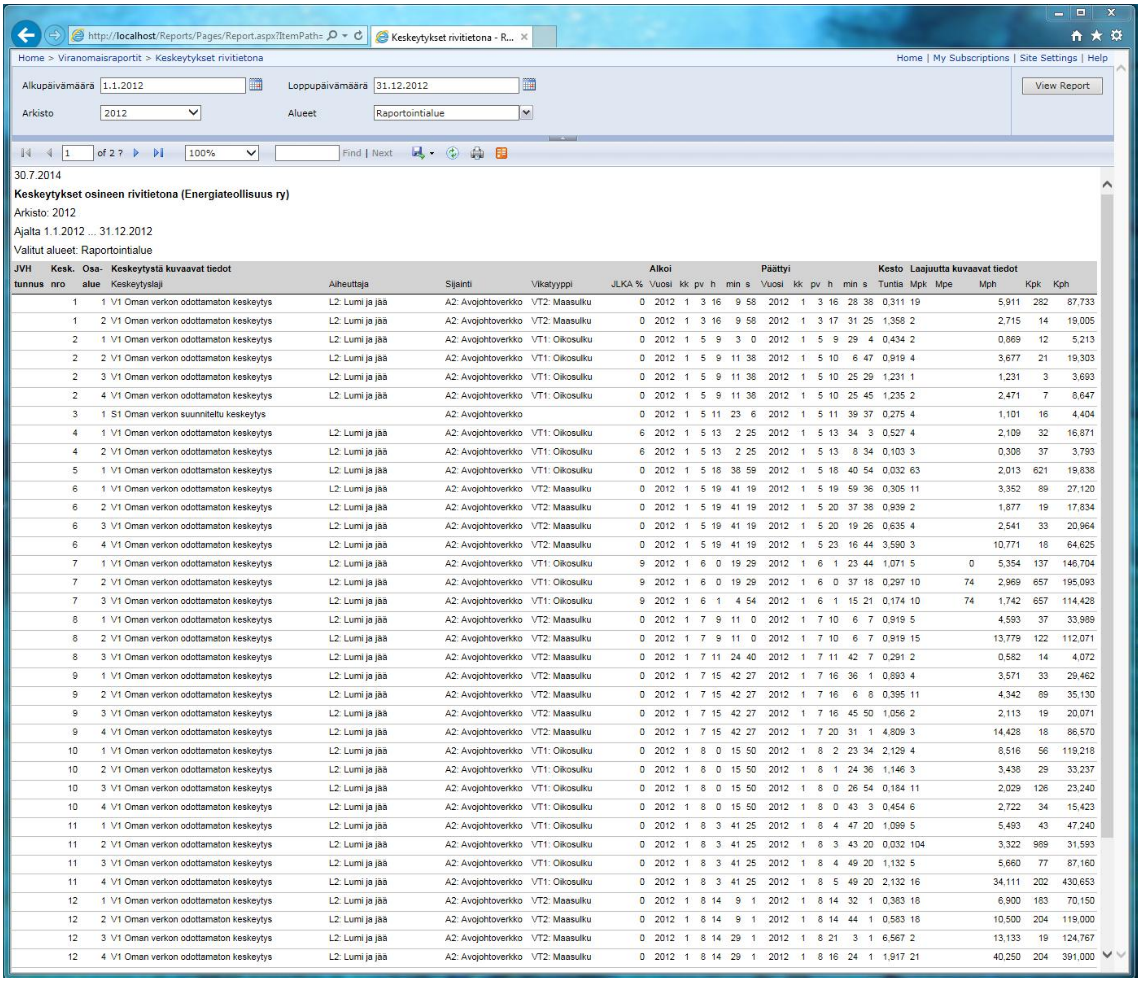


Figure 16. MV conductor and distribution substation summary reports for Energy Authority.

Distribution network development plans and required data for Energy Authority can't be reported yet using DMS600 software and Reporting Services at the present but as a part of thesis several methods and solutions were developed like presented in Chapter 8.

Required outage area report for ET, dealt in Chapter 4 and Appendix H, can also be produced with Reporting Services. Like in the outage reports for Energy Authority, the desired time span, reporting area and DMS600's fault archive are given as a parameter for outage area report. An example of outage area report for ET is shown in Figure 17.



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Home > Viranomaisraportit > Keskeytykset rivitietona

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Alkupäivämäärä 1.1.2012 Loppupäivämäärä 31.12.2012

Arkisto 2012 Alueet Raportointialue

View Report

1 of 2 ? 100% Find | Next

30.7.2014

Keskeytykset osineen rivitietona (Energiateollisuus ry)

Arkisto: 2012

Ajalta 1.1.2012 ... 31.12.2012

Valitut alueet: Raportointialue

JVH	Kesk.	Osa-	Keskeytystä kuvaavat tiedot					Alkoi						Päättyi						Kesto	Laajuutta kuvaavat tiedot				
tunnus	nro	alue	Keskeytyslaji	Aiheuttaja	Sijainti	Vikatyyppi	JLKA %	Vuosi	kk	pv	h	min	s	Vuosi	kk	pv	h	min	s	Tuntia	Mpk	Mpe	Mph	Kpk	Kph
	1	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	3	16	9	58	2012	1	3	16	28	38	0,311	19		5,911	282	87,733
	1	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	3	16	9	58	2012	1	3	17	31	25	1,358	2		2,715	14	19,005
	2	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	5	9	3	0	2012	1	5	9	29	4	0,434	2		0,869	12	5,213
	2	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	5	9	11	38	2012	1	5	10	6	47	0,919	4		3,677	21	19,303
	2	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	5	9	11	38	2012	1	5	10	25	29	1,231	1		1,231	3	3,693
	2	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	5	9	11	38	2012	1	5	10	25	45	1,235	2		2,471	7	8,647
	3	1	S1 Oman verkon suunniteltu keskeytys		A2: Avojohtoverkko		0	2012	1	5	11	23	6	2012	1	5	11	39	37	0,275	4		1,101	16	4,404
	4	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	6	2012	1	5	13	2	25	2012	1	5	13	34	3	0,527	4		2,109	32	16,871
	4	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	6	2012	1	5	13	2	25	2012	1	5	13	8	34	0,103	3		0,308	37	3,793
	5	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	5	18	38	59	2012	1	5	18	40	54	0,032	63		2,013	621	19,838
	6	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	5	19	41	19	2012	1	5	19	59	36	0,305	11		3,352	89	27,120
	6	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	5	19	41	19	2012	1	5	20	37	38	0,939	2		1,877	19	17,834
	6	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	5	19	41	19	2012	1	5	20	19	26	0,635	4		2,541	33	20,964
	6	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	5	19	41	19	2012	1	5	23	16	44	3,590	3		10,771	18	64,625
	7	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	9	2012	1	6	0	19	29	2012	1	6	1	23	44	1,071	5	0	5,354	137	146,704
	7	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	9	2012	1	6	0	19	29	2012	1	6	0	37	18	0,297	10	74	2,969	657	195,093
	7	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	9	2012	1	6	1	4	54	2012	1	6	1	15	21	0,174	10	74	1,742	657	114,428
	8	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	9	11	0	2012	1	7	10	6	7	0,919	5		4,593	37	33,989
	8	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	9	11	0	2012	1	7	10	6	7	0,919	15		13,779	122	112,071
	8	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	11	24	40	2012	1	7	11	42	7	0,291	2		0,582	14	4,072
	9	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	15	42	27	2012	1	7	16	36	1	0,893	4		3,571	33	29,462
	9	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	15	42	27	2012	1	7	16	6	8	0,395	11		4,342	89	35,130
	9	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	15	42	27	2012	1	7	16	45	50	1,056	2		2,113	19	20,071
	9	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	7	15	42	27	2012	1	7	20	31	1	4,809	3		14,428	18	86,570
	10	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	0	15	50	2012	1	8	2	23	34	2,129	4		8,516	56	119,218
	10	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	0	15	50	2012	1	8	1	24	36	1,146	3		3,438	29	33,237
	10	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	0	15	50	2012	1	8	0	26	54	0,184	11		2,029	126	23,240
	10	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	0	15	50	2012	1	8	0	43	3	0,454	6		2,722	34	15,423
	11	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	3	41	25	2012	1	8	4	47	20	1,099	5		5,493	43	47,240
	11	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	3	41	25	2012	1	8	3	43	20	0,032	104		3,322	989	31,593
	11	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	3	41	25	2012	1	8	4	49	20	1,132	5		5,660	77	87,160
	11	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT1: Oikosulku	0	2012	1	8	3	41	25	2012	1	8	5	49	20	2,132	16		34,111	202	430,653
	12	1	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	8	14	9	1	2012	1	8	14	32	1	0,383	18		6,900	183	70,150
	12	2	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	8	14	9	1	2012	1	8	14	44	1	0,583	18		10,500	204	119,000
	12	3	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	8	14	29	1	2012	1	8	21	3	1	6,567	2		13,133	19	124,767
	12	4	V1 Oman verkon odottamaton keskeytys	L2: Lumi ja jää	A2: Avojohtoverkko	VT2: Maasulku	0	2012	1	8	14	29	1	2012	1	8	16	24	1	1,917	21		40,250	204	391,000

Figure 17. Outage area report for ET.

General information report for ET, presented in Chapter 4 and Appendix G, can’t be directly reported using Reporting Services but the required data can be easily picked from the network asset reports.

7. DEVELOPMENT NEEDS TO DMS600 SOFTWARE

This Chapter covers the development needs to DMS600 NE and DMS600 WS programs. Presented development needs are mainly based on Energy Authority's and ET's reporting requirements as well as interviews with the DSOs' representatives.

7.1 Metering Point-specific Outage Reporting Model

ET requires DSOs to report outages metering point-specifically onwards 2015, hence the customer codes in faults must be saved to database during reporting. Outage reporting in metering point level cannot be done using present DMS600 program version, but the functionality have to be implemented to software and installed to all Finnish DMS600-users by the end of 2014.

Currently DMS600 saves the affected distribution transformers and LV networks in MV faults to DMS database and the customers are retrieved when reporting the faults in DMS600 WS. MV network's switching state is accurately up to date and saved to database. LV network's switching state is also saved but the switching state management and accuracy of LV network's topology depends on DSO's operative personnel and their activity. Faults in the LV network can be reported if desired and the reports are already saved metering point-specifically to database. Outages in the LV network are also possible to report utilizing AMR event data. In addition, also the 110 kV network is included in outage reporting and fault management as ET requires.

7.2 Environmental Analysis for Network Assets

Due to new Electricity Market Act and authority reporting requirements, DSO's are obligated to report environmental information of their network assets. According to distribution network development plan requirement, DSOs are demanded to report

- Number of metering points in the town plan area and outside the town plan area
- Amount of overhead lines located in the forest
- Amount of overhead lines located between the road and forest

Also the number of metering points as well as the amount of MV and LV lines that fulfill the reliability requirements set in article 51 § are obligated. ET requires the town plan area information for metering points in the new outage reporting model from the beginning of 2015.

Energy Authority's and ET's environmental analysis requirements for network assets raise various questions regarding the source data and required applications that can produce the needed information, such as:

1) What source data is needed?
2) Where the source data can be acquired?
3) How the source data should be utilized?
4) Is there a tool that can process and analyze the source data?
5) What kind of a tool is needed?

Open data providers and available data as well as developed methods and tools for analyses are dealt further in Chapter 8.

7.2.1 Tool to Calculate the Excavation Classes for Underground Cables

In the 3rd regulatory period, DSOs are required to report the amount of underground cables in each excavation class for Energy Authority annually based on CLC data, like discussed in Chapter 4. Since the beginning of the 3rd regulatory period, CorineTool application has been utilized in analysis, which is developed by M.Sc. Jukka Saarenpää from University of Eastern Finland according to ABB's specification. CorineTool is implemented by Python programming language and it uses Esri's ArcGIS software and its geoprocessing functionalities.

CorineTool reads the underground cable data from the input file given in CSV (Comma-Separated Values) format as polylines and cuts the lines by land type borders. Subsequently CorineTool calculates the length of cables in excavation classes two and three and creates output file in CSV format with necessary results. Results of the CLC analysis must be copied to 'CLC2' and 'CLC3' columns of the MV and LV section tables from the output file. [Saa12]

According to interviews, all DSOs stated that the CLC analysis should be performed using DMS600 NE by end-user's request.

Due to complicated usage of CorineTool and the dependency on expensive ArcGIS software in data processing, new CLC analysis functionality were created during the thesis by Mr. Erkka Martikainen.

7.3 Distribution Reliability Requirements Fulfillment Analysis

One of the most essential questions from the thesis point of view is how to analyze the distribution reliability requirements fulfillment in the distribution network. In the distribution network development plans, DSOs are required to report the amount of MV and LV lines as well as the number of metering points that meet the distribution reliability requirements. All lines that fulfill the requirements can be reported directly but in case of metering points, the whole feeding path from substation to customer must meet the set requirements.

Because the network structure that fulfills the reliability requirements isn't determined in the law or authority's requirements, DSOs can define the criterion by themselves. This criterion was trashed out in the interviews and it was the major theme in the discussions. All interviewed DSOs referred to major disturbance proof (MDP) network as their criterion but the opinion, what it involves differed. All DSOs agreed that underground cables and overhead lines in the open space, e.g. in the field and clear felling area are involved. Overhead lines located on the roadside shared DSOs options; LSOY defines overhead lines with covered conductors (PAS lines) on the roadsides in the MDP network in all circumstances unlike OSS. KSAT in turn requires information about tree stand height before the overhead line on the roadside can be defined to be involved in MDP criterion. Also the possibility to include the lines that can be repaired within set time limits (six hours in the town plan area and 36 hours outside the town plan area) in the analysis were discussed. All DSOs agreed that repairing possibility should be included and graphical tool should be implemented to DMS600 NE that enables user to mark such areas in database where network is possible to repair within required time. Regarding to this, representatives of OSS want the fault repairing resources to be taken into account in such analysis.

Method and algorithms for reliability requirements fulfillment analysis for lines and metering points were developed, based on interviews. Algorithms are presented and described in Chapter 8.

7.4 Development Needs to Network Planning Tool

DMS600 NE is used also for network planning and plan management. Network planning module enables user to design the network before importing the plan to database. With the network planning function, user can compare alternative network structures, monitor investment and outage costs of the planned network as well as dimension individual line section from economical aspect. Also simulation and network calculation of the planned network can be made. [ABB12]

7.4.1 Database Structure

Most of the inserted, updated and deleted network data in planning mode is saved to separate planning file and no changes to network database are made. [ABB12] Only the length and costs of new and renewed MV and LV lines as well as count and costs of new distribution transformers and disconnectors are written to NETWORK_PLAN table of the network database. In addition, also the filepath, title, planner, created and changed dates as well as calculation parameters and calculated SAIFI, SAIDI, ASAI and NDE indices of the network plans are written to database.

More versatile data from network plans need to be stored to database. Hence, the data required in sections 2 and 4 of the network development plans for Energy Authority can be reported properly. Ideal implementation is to save all network data of the planned network to database like in normal data saving mode. Thus, also importing the designed network to permanent database eases.

7.4.2 Long-term Planning

Need for long-term planning tool to support DSOs strategic network development came up in the interviews. Long-term planning tool is needed for DSOs own needs but also when creating the network development plans and related reports for Energy Authority.

Long-term planning tool should first form overall picture from the existing network by current state analysis. Analysis should contain electrotechnical as well as economic perspectives and produce information about:

- Electrical state of the network
- Power quality
- Reliability and performance of the network
- Outage as well as total costs
- NPV of the network
- Authority requirements fulfillment

After the current state analysis of the network, development needs and targets are known and located. Subsequently tool should compare created network plans by simulating and analyzing alternative network structures. Tool should provide information about planned network in different scenarios and alternative plans by analyzing electrical state, reliability, outage and total costs and NPV of the network as well as authority requirements fulfillment in case of each subplans. Tool should iterate the best solutions and find the best planning path towards to the target network. Long-term planning process and needed functionality are illustrated in Figure 18.

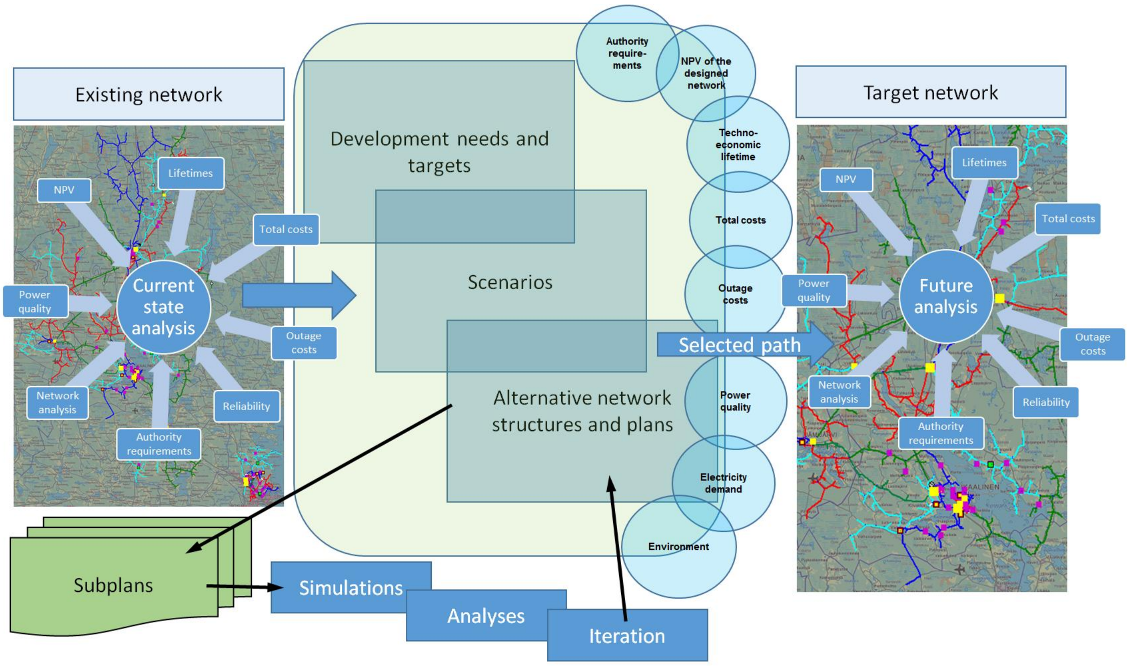


Figure 18. Long-term planning process and needed functionality.

Described tool and functionality supports DSO's strategic network development and investment management. Also DSO's economic development can be easily assessed and monitored. Network should be able to be planned systematically towards the target network and this requires the iteration and analysis of the alternative solutions. In future network planning will be focused more and more to reliability improving, hence the effect of network investments to the reliability and NPV of the network must be evaluated more precisely.

7.5 Modification Needs to Customer Information

Due to distribution reliability requirements and required data in distribution network development plans, important metering points from the society point of view and holiday houses should be able to be queried and separated from customer information.

Important metering points should be able to be illustrated from the DMS600's background map in network planning when designing investments and renovations as well as in topology management when prioritizing feeders and metering points in fault situations.

Number of holiday houses is needed when evaluating the distribution reliability requirements for Energy Authority because holiday houses are excluded from the targets of 2019 and 2023. Information of holiday houses is also needed when calculating CELID-6-TPA, CELID-36-NTPA and CELID-DRR indices, presented in Chapter 8.

Important metering point and holiday house information might be imported and saved to network database from CIS in numerous manners, depending on the DSO and CIS vendor. After all, to be able to use the information for DMS600 and reporting purposes generically, information should be retrieved and saved to database from CIS or other external data source in uniform format regardless of the CIS vendor or DSO. Hence, the CUSTOMER table needs own columns for such metering points.

7.6 Demolition of Network Components

Demolished network components must be reported annually in the network asset reports as discussed in the Chapter 4. If DSO must replace network components that still have techno-economic lifetime remaining due to new Electricity Market Act and distribution reliability requirements, the NPV of the demolished components is compensated in the allowed return on capital. The compensation is possible in case of 20 kV and 0.4 kV overhead lines, pole-mounted distribution substations, line disconnectors and remote controlled disconnector stations.

Demolition of components isn’t supported properly in DMS600 NE and the demolished components can’t be reported with Reporting Services. In current DMS600 version, only deleted MV and LV line sections are stored to database if desired and only the time of the data change is saved. Hence, the demolished components can’t be reported properly if the network data management and editing isn’t in real-time because the demolition date is the time of data change. Developed functionality for demolishing the components is described in Chapter 8.

7.7 Network History Database

DMS600 needs network history database; hence network asset and outage reports can be generated from the past properly. History database should provide the network asset data from the desired date given by user. History data is also required in the outage reporting because nowadays customer count is calculated in DMS600 Reporting Services’ reports from the database at the reporting moment, not using the customer count from the time of the fault. Hence, the reliability indices and other indices of quality of supply are not calculated correctly. Network history database should also contain network change history data, such as:

- When the components and line sections are created, changed and demolished
- When new customer has been connected to network
- When customer's LV network has changed
- Who has made the changes to database

In addition to network asset reports, network history database would be very useful in network operation process when simulating the past. Because network should be presented from the database as it was at that time, not like it‘s at the present.

Network history database requirements are described and dealt in Chapter 8.

8. DEVELOPED SOLUTIONS AND METHODS

This Chapter covers the developed solutions and methods to described needs in Chapter 7. The most of the presented solutions and methods are already implemented to DMS600 software during the thesis but part of the methods is only in specification and theoretical level. Summary of the developed solutions and methods is presented in subchapter 8.11.

8.1 Metering Point-specific Outage Reporting

Outage reporting in metering point level will be implemented in the DMS600 4.4 FP1 HF1 version which will be released at end of 2014. In the designed DMS600's metering point-specific outage reporting model, the affected network service points are saved to OTG_STEP_AREA table of the DMS database from each MV fault. With the information about affected network service points, the affected metering points can be queried from the database easily. All affected metering points will be attached to the right outage area when reporting the faults. Information of metering point's reliability requirement class (town plan area/not town plan area) will be also saved to outage reports, utilizing developed ShapefileTool's analysis presented in Chapter 8. It's noteworthy that also affected distribution transformers' codes must be saved to database like nowadays because network service points may move to other LV network after the outage is reported.

There are few challenges for DMS600 software when moving to ET's metering point-specific outage reporting model, such as:

- In order to report the affected metering points correctly, LV network's topology must be up to date
- Possible errors in the reports e.g. overlapped outage areas, differences to the event list and suspiciously broad and long interruptions, are not detected automatically
- ET's old and new codes for interruption types and reasons of interruption as well as fault location and types must be in used parallel. That's because outages from 2014 must be reported according to old reporting model in 2015 but outages in 2015 must be saved to database according to new requirements

Next program version, DMS600 4.4 FP1 HF1, alerts user from overlapped outage areas during reporting. Monthly analysed reports and auxiliary reports enable early address to problems and ensure valid outage data. New codes, presented in Chapter 5, will be delivered to all DMS600-users before the end of the year 2014 and they're used in parallel with the old ones, hence reporting requires vigilance from the operator.

8.2 ShapefileTool

ShapefileTool application was developed as a part of the thesis. ShapefileTool is based on two different applications for two different purposes. Other application has been developed for calculating the number of metering points located in the town plan area and the other one for calculating the amount of underground cables in different excavation classes. Because both tools and analyses were based on Esri shapefile data, the applications and their functionalities were integrated, hence MV sections, nodes and any given shapefile can be analyzed. Author developed ShapefileTool so that also LV sections can be analyzed. Mr. Erkka Martikainen started the further development and fine-tuning of the tool during the thesis project. ShapefileTool is implemented by object-oriented C# programming language and is used with MS Windows' command-line interpreter, cmd.exe (Windows Command Prompt). ShapefileTool can be used for basic shapefile analysis as well as CLC analysis.

8.2.1 Basic Shapefile Analysis

In basic shapefile analysis, tool analyzes given shapefiles and network information from the DMS600's network database. All MV and LV line sections as well as nodes within shapes are written to database. Paths of the ShapefileTool application and shapefile material are given as a command line parameter. Shapefile data is written in four different Metadata tables that are created in the network database at first ShapefileTool run and are used to data storing ever since. Created metadata tables are:

- METADATA_FILE
- METADATA_MV_SECTION
- METADATA_LV_SECTION
- METADATA_NODE

METADATA_FILE table contains a list of analyzed shapefiles with the paths, names and IDs. METADATA_MV_SECTION and METADATA_LV_SECTION tables contain IDs of the analyzed shapefiles and line sections that are inside the shapefiles' polygons. The length of each MV and LV line sections overlapping with different polygons as well as one key-value pair for each overlapped line sections are written in the tables. METADATA_NODE table in turn contains a list of all nodes located inside the different polygons of analyzed shapefiles. Individualized node code, shapefile's ID and key-value pair of different polygon types are written in the table also. ShapefileTool's basic shapefile analysis function is illustrated in Figure 19.

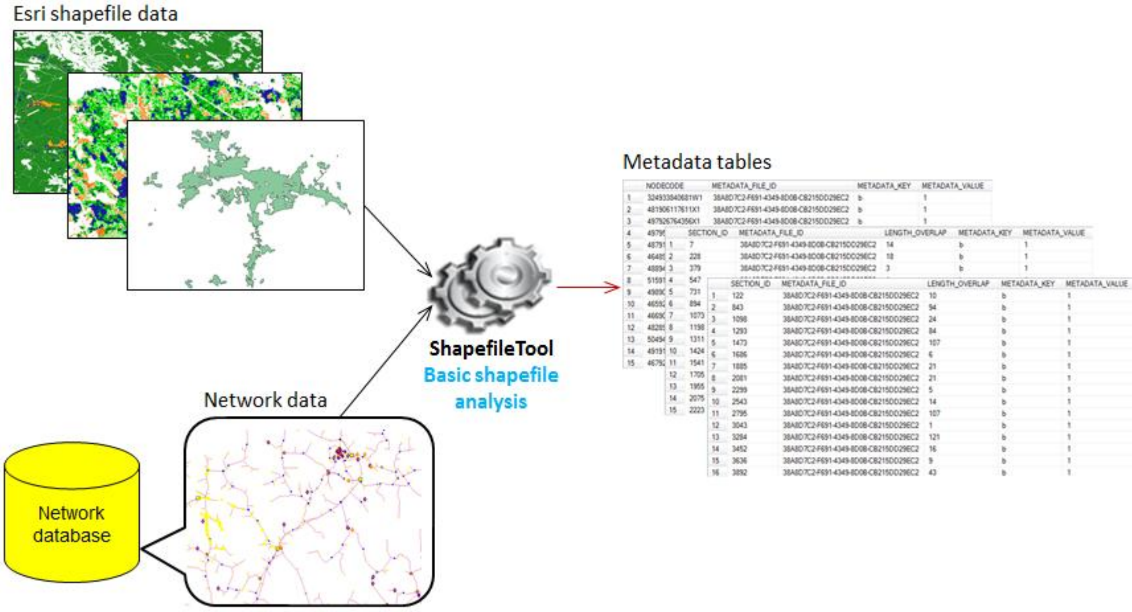


Figure 19. ShapefileTool’s basic shapefile analysis.

Shapefile data from the different metadata tables can be deleted easily using delete command with the cmd.exe. With the help of ShapefileTool’s analysis and produced information, different reports and graphical database queries, based on any shapefile can be created easily, e.g. overhead lines in the fields and forest or metering points in the town plan area. Several different reports for Energy Authority and ET were written as a part of the thesis. Implemented reports are presented later in this Chapter.

8.2.2 CLC Analysis

In CLC analysis, the amount of underground cables in the excavation classes two and three are calculated and written to database using CLC data in vector format. CLC analysis can be started using ‘-CLC’ parameter in cmd.exe, after the path of ShapefileTool is given. Subsequently the file path of CLC data is fed; hence, the usage is similar comparing to basic analysis.

At first run, tool creates CLC_CLASS table to network database as well as ‘CLC2’ and ‘CLC3’ columns to MV and LV line section tables, if they don’t exist already. CLC_CLASS table is used as an auxiliary table in the calculations, containing excavation class number, class name and CLC code and info columns for CLC classes two and three like presented in Figure 20.

	EXCAVATION_CLASS	CLASS_NAME	CLC_CODE	CLC_INFO
1	2	Regular	112	Discontinuous urban fabric
2	3	Difficult	111	Continuous urban fabric
3	3	Difficult	121	Industrial or commercial units
4	3	Difficult	122	Road and rail networks and associated land
5	3	Difficult	123	Port areas
6	3	Difficult	124	Airports
7	3	Difficult	332	Bare rock

Figure 20. CLC_CLASS database table.

In the analysis, ShapefileTool checks the borders of the network area and analyzes only relevant area of the given CLC file. Only MV and LV line sections that are underground cables are queried from database and taken into calculation. Tool analyzes all CLC classes and calculates the length of each line sections in excavation classes two and three using the definitions saved in CLC_CLASS table.

The operating principle of the CLC analysis is illustrated more precisely in Figure 21 and Figure 22. Figure 21 shows the studied MV line section and line section data.

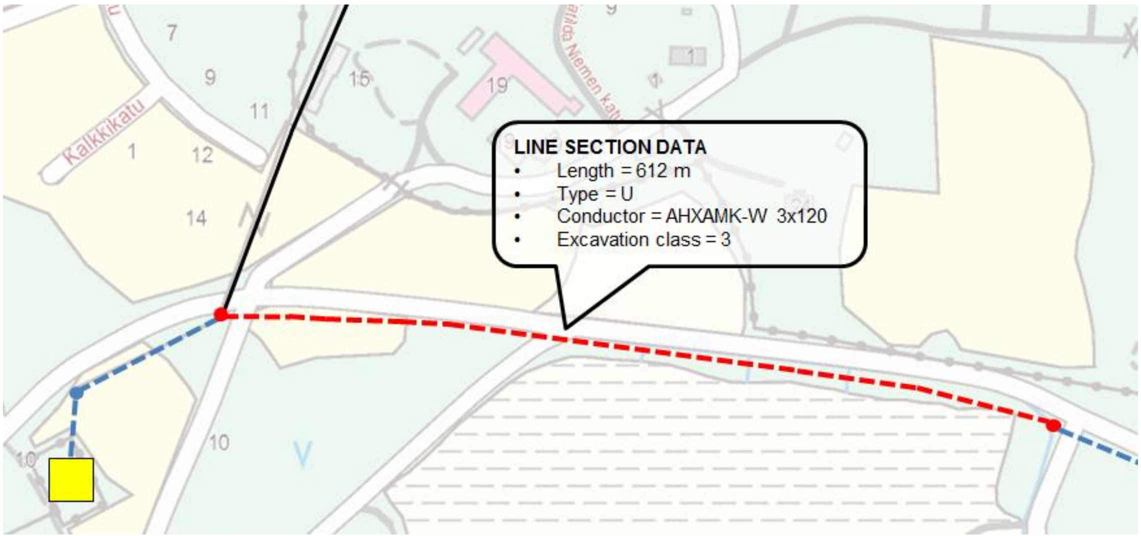


Figure 21. Studied line section.

Figure 22 shows the database structure as well as utilized input data and the outcome of the CLC analysis for studied MV line section.

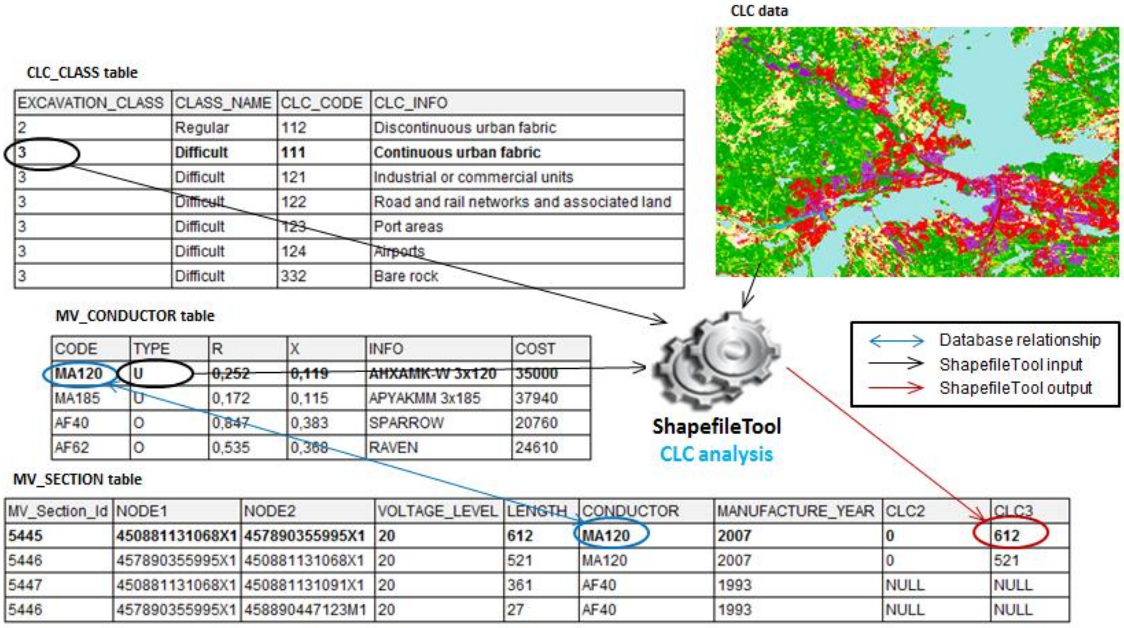


Figure 22. Operating principle of ShapefileTool's CLC analysis.

8.2.3 Future Development of the ShapefileTool

As a future development, ShapefileTool needs GUI so that end-user can graphically manage METADATA_FILE table and copy shapefile material to the DMS server from own computer. User should also be capable to start the ShapefileTool directly from the DMS600 NE’s menu bar and be able to give the path for tool and desired shapefiles graphically.

The dialog boxes of line sections and nodes need ‘Advanced Information’ button which opens dialog box presenting the list of metadata key-value pairs and overlapped length of the line sections by different polygon types. This is relatively easy to implement in database level by joining different component tables with metadata tables according to same section ID or node code. With the aid of this kind of functionality, user can easily check the result of the analysis from the dialog boxes, comparing the data to the background map. Even the errors in the produced data can be fixed manually from the free data form.

8.3 AreaImportTool

AreaImportTool was developed during the writing process as a continuum to ShapefileTool. Developed tool imports any given shapefile’s polygon areas to the DMS600’s network database as area component. Only relevant shapes to the DSO’s network area are converted and imported to database. Many shapes have holes in them, thus user can choose to only draw the outer ring of the shapes or draw holes as separate area components. With the help of the import tool, e.g. town plan and forest areas from the shapefiles can be seen in DMS600’s GUI upon geographical background map.

AreaImportTool is also implemented by C# programming language and used with MS Windows' cmd.exe. File path of the AreaImportTool application and desired shapefile data are given as a command line parameter and tool writes the data of given shapefile to network database.

Metadata of the imported areas, such as names, IDs, descriptions and types are written to AREA table. Section points and coordinates of the area components are written to AREA_POINTS table, in turn. In DMS600 4.4 FP1 HF1 program version, which will be released at end of 2014, polygon areas are saved as a 'Shapefile Areas' to AREA table. DMS600 NE's GUI and imported town plan area of Virrat is shown in Figure 23 as an example.

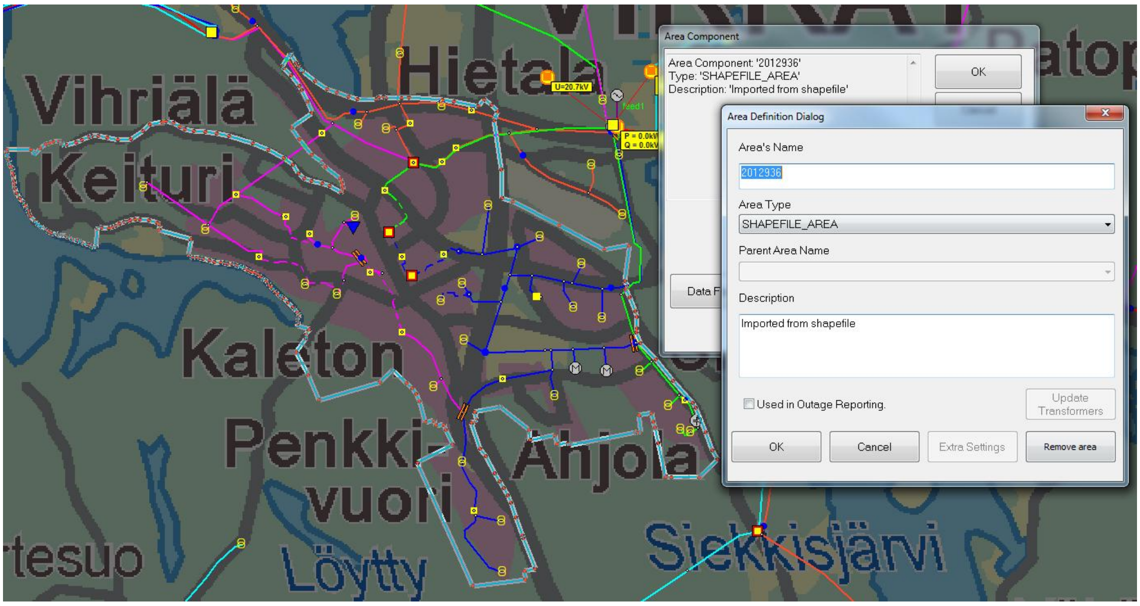


Figure 23. DMS600 NE's user interface and imported town plan area of Virrat.

8.3.1 Future Development of the AreaImportTool

As a future development, AreaImportTool should be modified so that it can import any kind of data from given shapefiles, not just polygons. Hence, the network information like line sections and different components should be able to be imported as a vector form data with the line routes, section points, nodes and values from other NIS or GIS systems. In addition, relevant GUI is also needed.

8.4 Environmental Analysis for Network Assets and Open Data Utilization

Energy Authority's and ET's new reporting requirements demand environment information of DSOs network assets. Developed ShapefileTool and open data utilization play key role in environmental analysis. ShapefileTool can analyze any given shapefile and DSO's network database. Open data needed in different analyses is usually available in information providers' websites.

Open data is certain data in machinery readable format that is available to everybody and is reusable for any purpose without specific permission free of charge. [Wik14]

8.4.1 Metering Points in the Town Plan Area

Number of metering points inside and outside the town plan area is required in distribution network development plans. Town plan information is also needed in ET's new metering point-specific outage reports.

All nodes and line sections, i.e. network components and lines in the town plan area can be written to metadata tables of the network database using ShapefileTool's basic analysis and town plan area data.

Town plan area data in Esri shapefile format for whole Finland is produced by Finland's Environmental Administration and can be downloaded from OIVA environment and geographical information service's website. Town plan area data is in ETRS-TM35FIN coordinate system and its last update date is 12.11.2013.

An example of town plan area data is given in Figure 24.

Figure 24. Town plan area of Tampere city in shapefile format.

8.4.2 Amount of Overhead Lines in the Forest

Amount of overhead lines in the forest is required to be reported in distribution network development plans. With the help of ShapefileTool and forestry information, all MV and LV line sections in forest can be written to metadata section tables.

Forestry information can be obtained from land class data in ETRS-TM35FIN coordinate system. Land class data from 2011 for whole Finland is produced and published by Finnish Forest Research Institute (Metsäntutkimuslaitos, Metla). Data is in raster format and can be downloaded from Metla's website for free. Land class data contains three classes: woodland, forest land of low productivity and wasteland, as seen in Figure 25.

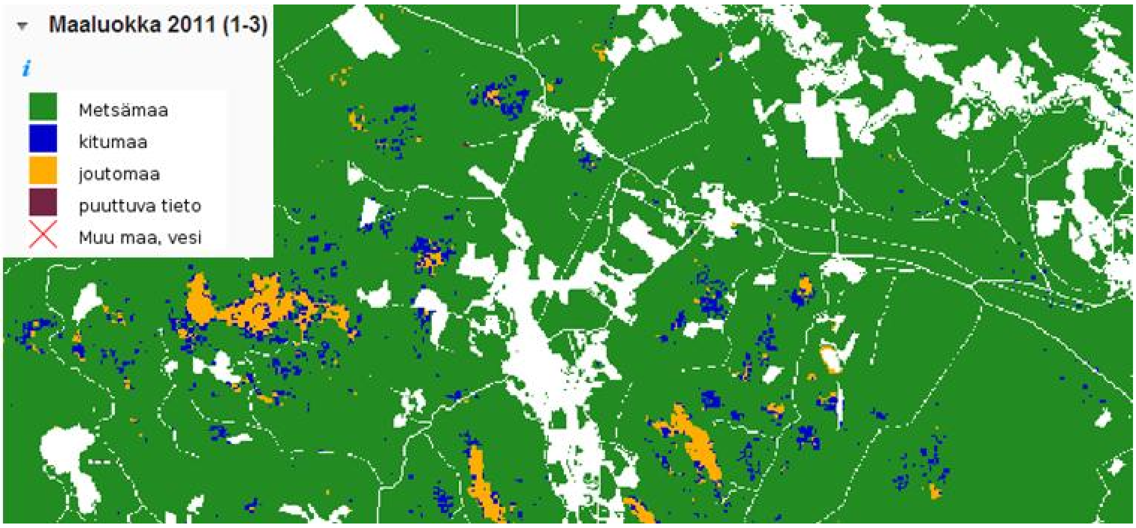


Figure 25. Example of forest data.

Land class data is in GeoTIFF format, hence it must be vectorized and the classes must be named by user before it can be utilized for ShapefileTool and DMS600 purposes. After the ShapefileTool's basic analysis, the amount of MV and LV lines in forest can queried from the network database easily in DMS600 Reporting Services.

8.4.3 Amount of Overhead Lines between Road and Forest

DSOs are also obligated to report the amount of overhead lines between road and forest in distribution network development plans.

Road data can be obtained from National Land Survey of Finland's (Maanmittauslaitos, MML) background map material (1:10 000) in ETRS-TM35FIN coordinate system by converting it to vector format and gathering the road vectors to one shapefile manually. MML's general map material can be downloaded from MLL's website free of charge. An example road data is given in Figure 26.

Figure 26. Example of road vector data.

The challenge in the road data utilization is that the data contains only the center line of the road and no information about the road width is available; hence the amount of overhead lines between road and forest cannot be calculated directly, based on road vectors and Metla's forestry data.

In the developed algorithm, overhead lines on the roadside need to be calculated first and then the overhead lines on the edge of the forest. To be able to calculate the above-mentioned line sections, following parameters are needed to be given by user:

(a) Distance from the center line of the road to line section
(b) Distance from the line section to the edge of the forest

Line section is on the roadside if its section points are located within the area formed by the center vector of the road and line drawn parallel to the road as far as given in parameter (a) on average. Line sections located on the edge of the forest are calculated similarly; from the section points to the edge of the forest using parameter (b). All line sections that meet the conditions set in (a) and (b) are located between road and forest. Perpendicular distances from the line section to center line of the road and edge of the forest can be calculated using section points' coordinates and scalar product function.

Figure 27 illustrates the calculation of the line sections between road and forest.

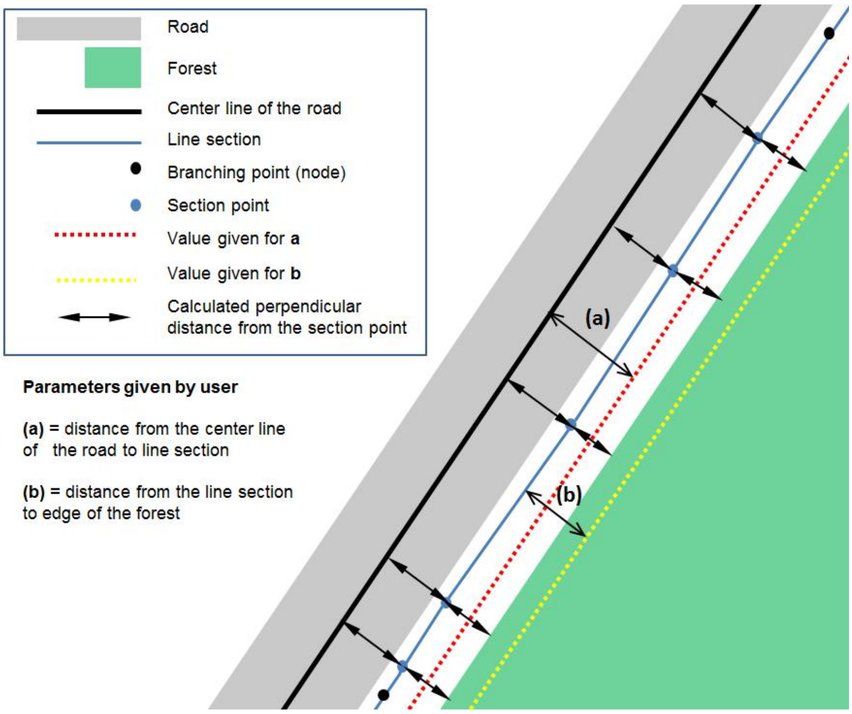


Figure 27. Calculation of the line section between road and forest.

Implementation of the developed algorithm to ShapefileTool and DMS600 NE might be challenging and calculating the whole distribution network can be time consuming.

8.4.4 Tree Stand Height Data

According to interviews, the tree stand height information needs to be brought to DMS600 NE to evaluate the distribution requirements fulfillment for overhead lines properly.

Metla provides tree stand mean height data from 2011 for whole Finland in their file service. Stand mean height data is provided in GeoTIFF format in ETRS-TM35FIN coordinate system. Stand mean height data contains ten different height classes. An example of Metla’s stand mean height data is shown in Figure 28.

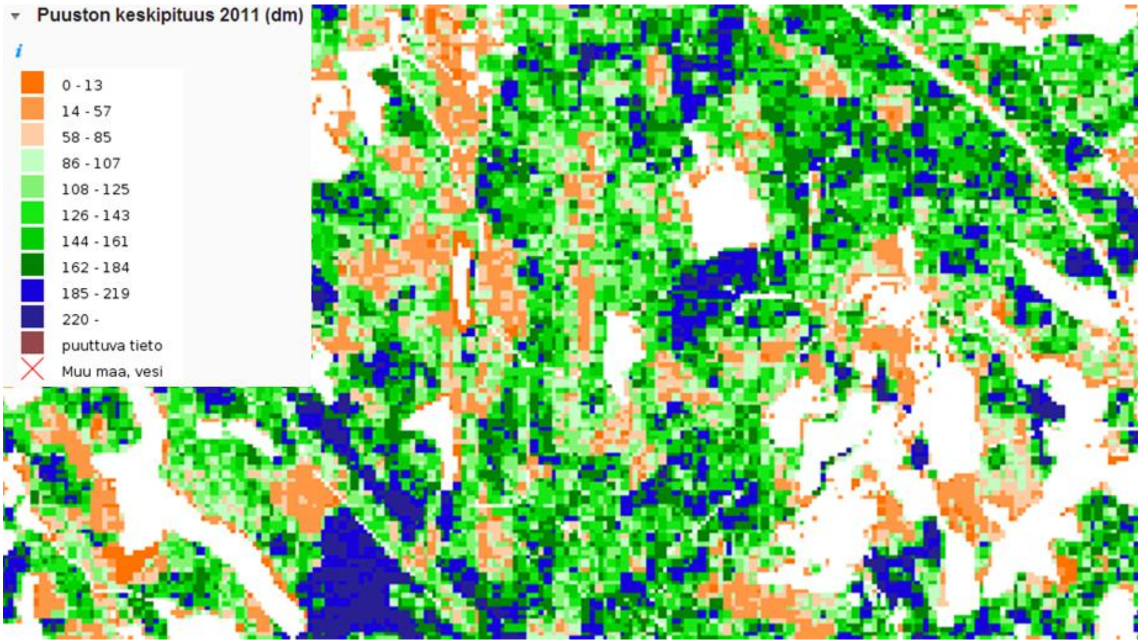


Figure 28. Example of stand mean height data.

Stand mean height data needs to vectorized because it's in GeoTIFF format and the classes must be defined by user before it can be utilized in ShapefileTool's analysis and imported to database with AreaImportTool.

8.4.5 CLC data and Excavation Classes

CORINE Land Cover (CLC) data is provided and updated by Finnish Environment Institute (SYKE). CLC data can be downloaded free of charge from SYKE's website and it includes land type information for whole Finland. Data is last updated in 2006 but the next update will be at the end of 2014.

CLC data is available in raster and vector formats. Raster data consists of 25 m^2 grids and the vector data is created by generalized raster data so that the smallest distinguishable area is at least 25 ha large and 100 m narrow. [Saa12]. An example of CLC data and different classes are presented in Figure 29.

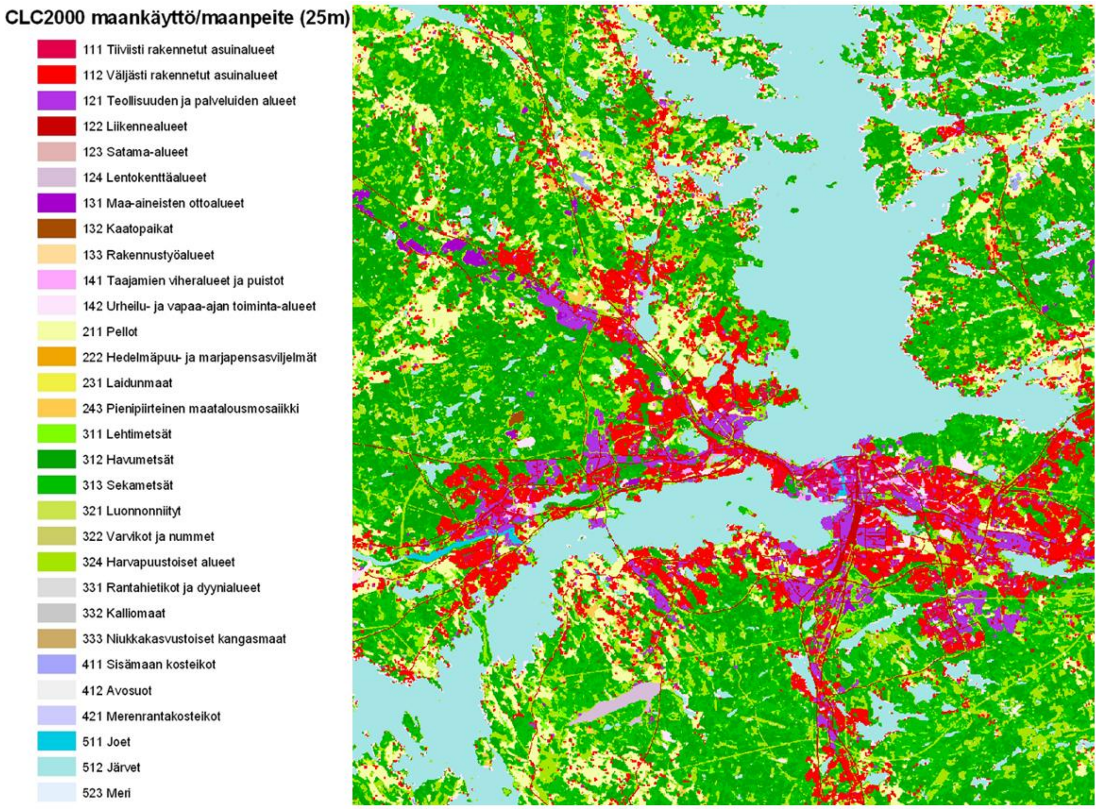


Figure 29. Example of CLC data.

8.4.6 Problems in the CLC analysis for Underground Cables

There are several problems and weaknesses in the excavation class calculations for underground cables utilizing CLC data with DMS600 and ShapefileTool. Determined excavation classes and different types of planning areas in the CLC data are weakly correlated to the excavation costs because the effect of the soil type is not taken into account, this causes problems especially for the DSOs in rural areas. Other problem is that the utilized CLC data is from year 2006 and isn't updated ever since. The objective of excavation class usage in the RV calculation of the network is good but in practice absurd when almost 10 years old source data is used. According to the requirement, 25 m^2 raster form data must be used in calculation which is one giant file of the whole Finland and its processing is difficult and slow. The generalization of vector form data from raster data restricts the accuracy, hence small and narrow areas, such as roads, cannot be distinguished. Raster form CLC data cannot be used in calculations without first vectorizing it, which causes few problems. Using vectorized raster data that preserves the grid makes the calculations extremely heavy and time consuming. On the other hand, using vectorized data that doesn't preserve the grid, shows some areas (e.g. roads), as one giant shape when it's difficult to define the excavation class for road areas. [Saa12] In addition, DMS600's network modeling doesn't contain cable route concept, hence the trench sharing coefficients have to be used instead of the actual trench lengths which skews the actual results and original objective of whole idea is wrecked.

8.4.7 Challenges in Open Data Utilization

The biggest challenge in open data utilization is the data format and data content diversity. Town plan area and CLC data are provided directly in vector format for whole Finland in one file and the data content is unique, hence the straightforward utilization in ShapefileTool's analysis is enabled. Also report creation in DMS600 Reporting Services is easy.

Metla's forestry data, in turn, is provided in GeoTIFF format and must be downloaded by one map tile at time. Metla's data must be converted to vector format before it can be utilized for DMS600 and reporting purposes. Data is vectorized manually using GIS and the classes must be named by user. Best solution would be that Metla provides the forestry data in shapefile format directly with pre-named classes. Thus the generic reports could be created for all Finnish DMS600 users.

8.5 Methods to Analyze the Distribution Reliability Requirements Fulfillment in the Distribution Network

Evaluation of the distribution reliability requirements fulfillment in the distribution network can be based on algorithms, analyzing the network characteristics and structure or on calculated reliability indices and outage history data.

Algorithms are the most effective way to analyze the requirements fulfillment and they give the most accurate results, while calculated indices indicate reliability in whole distribution system level on average. History analysis is based on DSOs actual outages but the inference of requirements fulfillment still bases on probability. Developed methods are described in the following subchapters.

8.5.1 Algorithms for Distribution Reliability Requirements Fulfillment

DSOs are required to report the amount of lines and metering points that fulfill the distribution reliability requirements (DRR) set in article 51 § of the new Electricity Market Act. When calculating the amount of lines, all MDP lines can be taken into account, but in case of metering points, the whole feeding path from substation to customer must be MDP network. As a part of the thesis, two algorithms to calculate these mentioned problems were developed.

According to interviews, DSOs opinions and definitions of MDP network differed; hence several parameters need to be given for the analysis by user, forming the rules and contents of the algorithms. First user needs to give the definition of MDP network in general level and subsequently define the contents for open space as well as overhead lines located on the roadside. Basic idea and given parameters are described in the following:

1) Parameters for DRR fulfillment (MDP network definition):
   - Underground cables

- Overhead lines in open space
- Overhead lines on the roadside
- Line section can be repaired in required time limits

2) Parameters for open space:
   - Fields
   - Clear felling areas
   - Open forest areas

3) Parameters for overhead lines located on the roadside:
   - PAS overhead lines in MV networks
   - ACSR overhead lines in MV network
   - ACSR overhead lines in LV network
   - AMKA aerial bunched cables in LV network
   - Distance from the center of the road to the side of the road
   - Distance from the line section to the edge of the forest

After the parameters are given, the network can be analyzed. First the line sections fulfilling the set DRR need to be analyzed and calculated. In the developed algorithm, whole distribution network is analyzed feeder-by-feeder, line section-by-line section, starting from the feeder node, obeying hierarchical MDP network definition given by user. The algorithm for MV and LV line sections is presented in Figure 30.

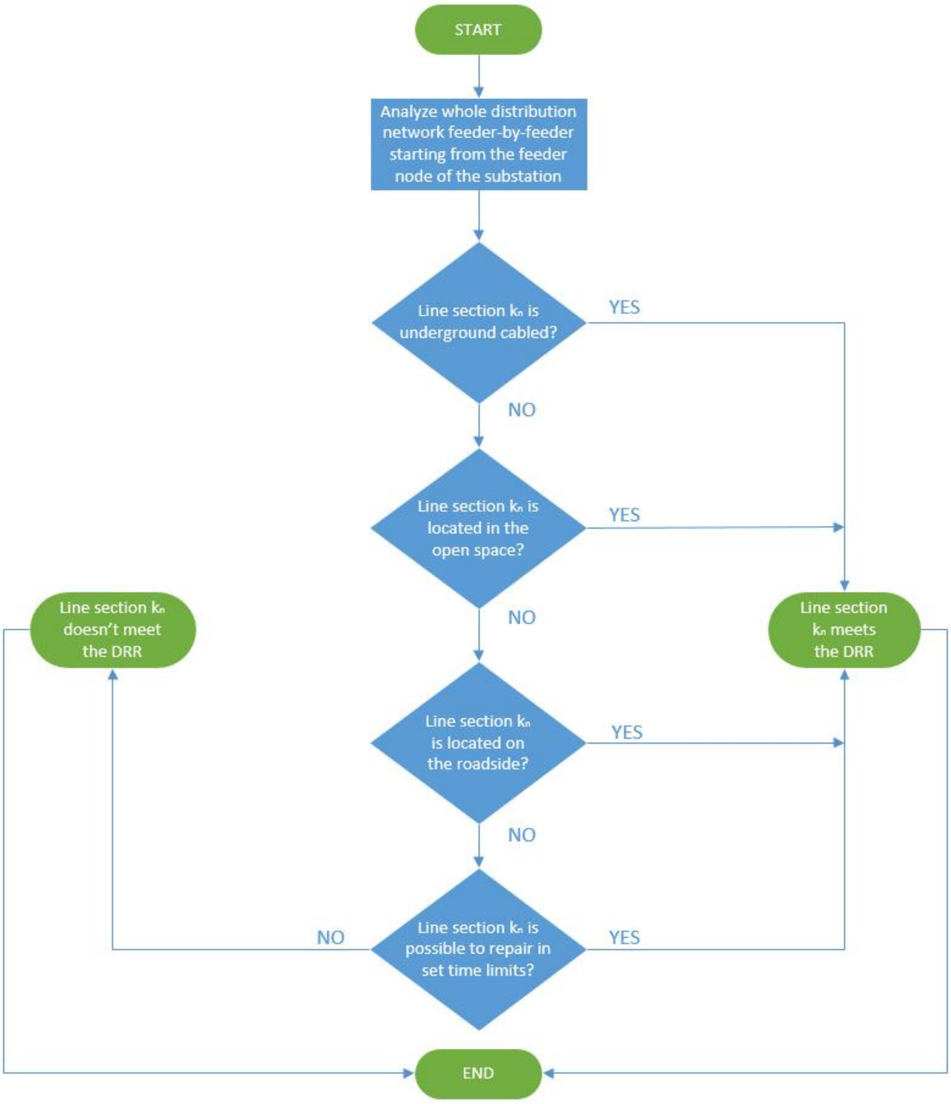


Figure 30. Flowchart illustrating the distribution reliability requirements fulfillment algorithm for MV and LV line sections.

All MV and LV line sections are analyzed according to given parameters and definitions. If line section meets the requirements, value ‘1’ is written to ‘DRR’ column of the line section table. After the analysis, individual MV and LV line sections that meet the set DRR can be queried from the database and reported to the authority. Algorithm could be triggered by user when desired or automatically when changes in the network data appear.

After the line sections are analyzed, the metering points in LV network that fulfill the requirements can be calculated using developed algorithm presented in Figure 31.

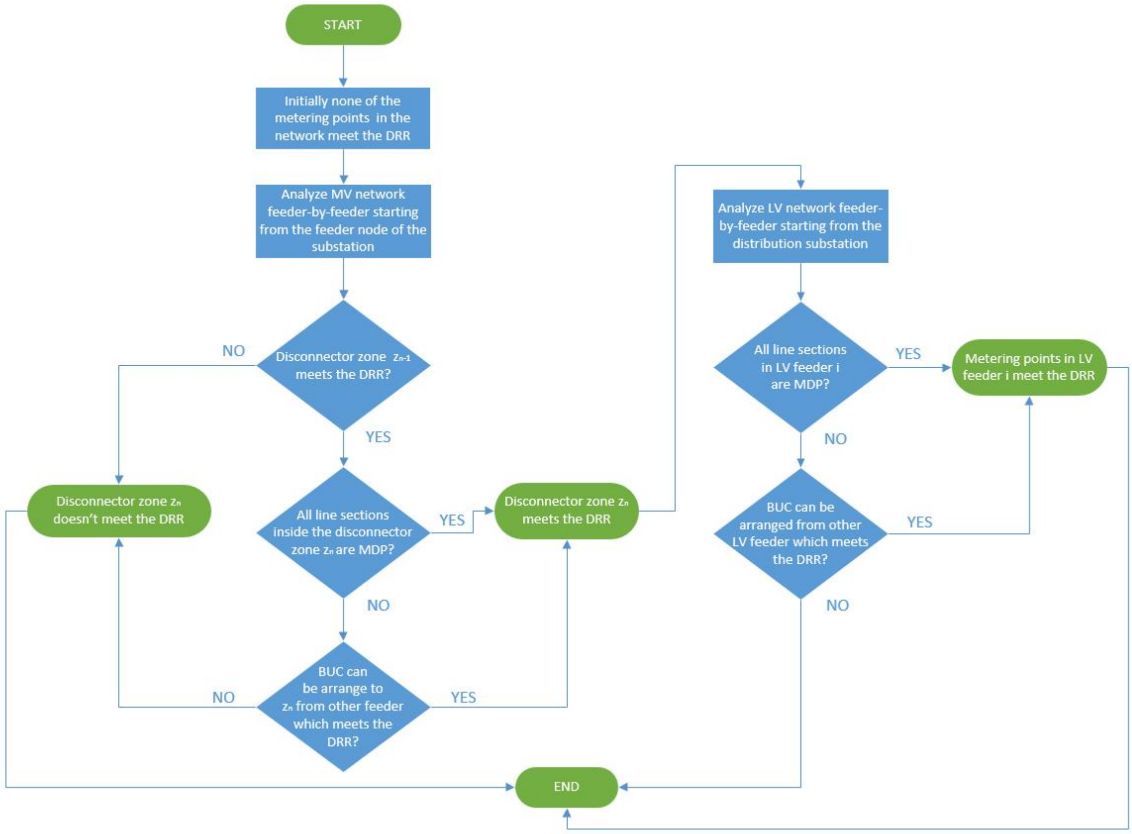


Figure 31. Flowchart illustrating the distribution reliability requirements fulfillment algorithm for metering points in LV network.

In the algorithm, metering points are initially defined so that none of them meet the set DRR and this is also written to database. Subsequently the MV network is analyzed feeder-by-feeder, disconnector zone-by-disconnector zone. Previous disconnector zone needs to meet the requirements before the studied one can. After that, algorithm exploits the results of line section analysis in disconnector zones by checking the MDP of all line sections inside the zone. Then possibilities to back-up connection (BUC) from other feeder that fulfills DRR are checked. If disconnector zone meets the DRR, connected LV networks are analyzed. LV network analysis is performed feeder-by-feeder, starting from the distribution substation. First the MDP of LV feeder is examined, utilizing the results of line section algorithm once again. Subsequently the possibility to back-up connections (BUC) from other LV feeders that meet the DRR is checked. The results of the analysis should be saved to CUSTOMER table; hence the metering points that meet the DRR can be queried from the database and reported to Energy Authority in the distribution network development plans. Algorithm needs DMS600's topology component to check the network topology and connectivity in the analysis. Algorithm could be triggered manually by user or automatically when switching state or network data change.

If the possibility to repair the line section within set time limits (6 h/36 h) is included to the algorithms, graphical area component tool is needed to DMS600 NE to mark the areas that can be repaired within set limits. Also the number of resources and the capacity of fault repair organization should be taken into account in the calculations somehow.

8.5.2 CELID Indices

Distribution reliability requirements fulfillment can also be analyzed using different variations of CELID-s index presented in Chapter 2.

When analyzing distribution network in the town plan area, where maximum allowed interruption duration is six hours caused by storm or snow load, CELID-6-TPA index can be used. CELID-6-TPA indicates the ratio of individual customers in the town plan areas that experienced a single interruption longer or equal than six hours. [Hei14] CELID-6-TPA index is mathematical formulated in Equation (22).

$$CELID - 6 - TPA = \frac{CN_{TPA(k \geq 6h)} - N_{T,ec}}{N_T - N_{T,ec}} \tag{22}$$

where

TPA	Town plan area
$CN_{TPA(k \geq 6h)}$	Total number of customers located in the town plan area that experienced an interruption with duration longer than or equal to six hours
$N_{T,ec}$	Excluded customers according to Finnish Electricity Market Act

In other areas, i.e. not town plan area, the maximum interruption duration is 36 hours. When analyzing other areas, the CELID-36-NTPA index can be used. CELID-36-NTPA indicates the ratio of individual customers not located in the town plan area that experienced a single interruption longer than or equal to 36 hours. [Hei14] CELID-36-NTPA index is presented in Equation (23).

$$CELID - 36 - NTPA = \frac{CN_{NTPA(k \geq 36h)} - N_{T,ec}}{N_T - N_{T,ec}} \tag{23}$$

where

$NTPA$	Not town plan area
$CN_{NTPA(k \geq 36h)}$	Total number of customers not located in the town plan area that experienced an interruption with duration longer than or equal to 36 hours

When analyzing the distribution reliability requirements fulfillment in the whole distribution network area (i.e. in town plan and not town plan areas), the presented

Equations (22) and (23) are merged. [Hei14] As a result, CELID-DRR index is derived as presented in Equation (24).

$$CELID - DRR = \frac{CN_{TPA(k\geq 6h)} + CN_{NTPA(k\geq 36\ h)} - N_{T,ec}}{N_T - N_{T,ec}} \tag{24}$$

where

DRR Electricity distribution reliability requirements set in the Finnish Electricity Market Act (6 h / 36 h)

If the excluded customers (e.g. the holiday houses) can be sorted out from the customer information generically, it could be easy to create reports to DMS600 Reporting Services that calculates the derived CELID indices from desired time span. But without the modifications to customer information and database described in Chapter 7, CELID reports and calculations aren’t possible.

8.5.3 History Analysis

Evaluation of the distribution requirements fulfillment in different parts of distribution network could also be based on outage history data. Probability to long interruptions is much greater on average in the parts of the network where the allowed outage times have exceeded multiple times before. DMS600 NE and WS should show actual outage data from the database in component dialog boxes, e.g. actual number of outages per year and longest outage times. Also SAIDI, SAIFI and KAH indices should be shown. Thus components and lines that exceed the set outage duration could be illustrated graphically in background map using graphical database queries (GDQ), requiring that GDQ support is implemented to line sections.

With the help of such analysis the parts of the network can be found where the allowed outage times have been exceeded, hence the network investments and renovation can be directed to right parts.

8.6 Functionality for Network Component Demolition

In order to report the demolished network components correctly, DMS600 NE user should be able to give the demolishing date after the component has been deleted from the GUI and database. Subsequently program should write the demolishing date to component table of the network database.

In such functionality, only ‘DEMOLITION_DATE’ column is needed to different network component tables. If ‘DEMOLITION_DATE’ column’s value is ‘NULL’, the component is still in the network but if the column includes a date, the component is naturally demolished at the particular time.

Described demolition functionality and database modifications allow the demolished components to be reported easily, using the demolition date from the created column. Demolished components could also be reported using network history database implementation described in the following subchapter.

8.7 Network History Database

Network asset history database implementation enables proper asset and outage reporting for authority and ET as well as several advantages for network operation, like discussed. History database implementation would also emphasize network planning function usage in DMS600 NE, like interviewed DSOs hoped. According to interviewed DSOs, DMS600 NE should be more planning-centered such that all network digitizing, network data editing and management should be performed always using network planning mode. After the new network data or change in existing network data is digitized into the plan file, the plan is imported to permanent database.

In database level 'CREATED_ID' and 'UPDATED_ID' columns should be added for every network component, node as well as line section tables and NETWORK_HISTORY table should be created to network database. Consecutive number is written to node or line section tables' ID columns when network data is changed; 'CREATED_ID' when component or line section is created and 'UPDATED_ID' when the component or line is somehow changed. NETWORK_HISTORY table should contain 'GUID', 'TIMESTAMP', 'PLAN_ID', 'PLAN_NAME', 'PLANNER' and 'PLAN_UPLOADER' columns. 'GUID' column corresponds to component's 'CREATED_ID' or 'UPDATED_ID' column's value and it's the primary key of the table and the time of network data change is written to 'TIMESTAMP' column. 'PLAN_ID', 'PLAN_NAME' and 'PLANNER' as well as 'PLAN_UPLOADER' columns contain information which network plan is responsible for the network data change and who has imported the plan file to database, if the change has come from the plan. Otherwise the they're left to 'NULL'

When adding new network component or line section, ID of the data change is written to 'CREATED_ID' column of the node or line section table and 'UPDATED_ID' column's value is left to 'NULL'. Current time is written to 'TIMESTAMP' column of the NETWORK_HISTORY table and 'CREATED_ID' value from the component table is written to 'GUID' column.

When changing existing network data, the value of old line section or node table's 'UPDATED_ID' column is changed from 'NULL' to consecutive number. Same ID is also written to new line's or node's 'CREATED_ID' column and the 'UPDATED_ID' is left naturally to 'NULL'. In NETWORK_HISTORY table, old line's or node's record remains unchanged and the record for new line or node is added. Figure 32 illustrates the behavior of DMS600 NE when moving existing MV line section (black line section) to new place.

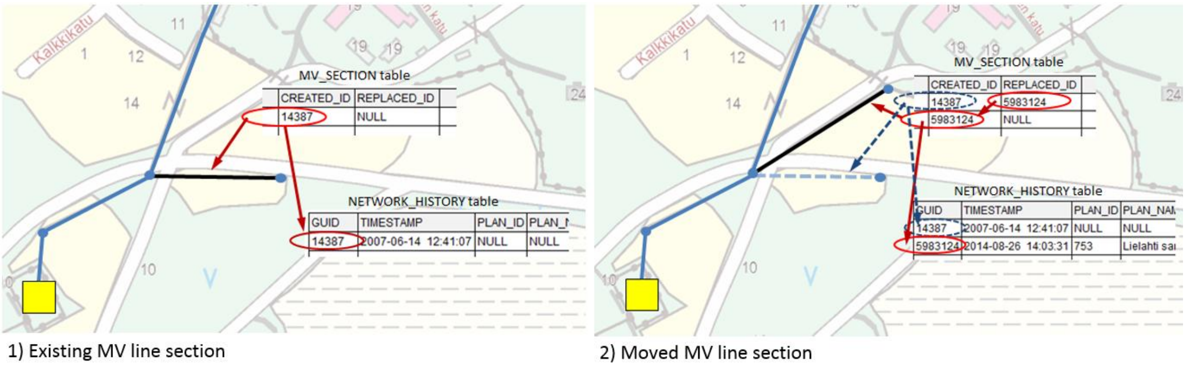


Figure 32. DMS600 NE's behavior when moving existing line section.

When deleting existing component or line section from the database, component's or line section's 'UPDATED_ID' column is changed from 'NULL' to consecutive number and isn't used anymore.

There are several benefits achieved with network history database implementation. Full history of network assets and data as well as data changes is stored to database with such implementation. Numerous reports of network asset information from the past can be created to DMS600 Reporting Services. Network data can also be queried from the desired date. Also demolished components and lines can be queried and reported with such implementation properly. In addition, full backlog of database changes and possibility to revert changes are also created. Now there is also information saved to database about who is responsible of the network data change as well as who has created the plan and imported it to database.

8.8 Investment Type Division and Reporting

In the 3rd regulatory period, DSOs are required to divide their network investments in expansion and replacement investments in network asset reporting, which isn't possible with the present DMS600 program version. In the DMS600 4.4 FP1 HF1 version, investment types for different network components can be given using implemented 'Investment type' field in the dialog boxes. 'Investment type' field in the dialog boxes contains radio buttons for expansion and replacement investments, like shown in Figure 33. Figure shows an example of MV section dialog box and database table.

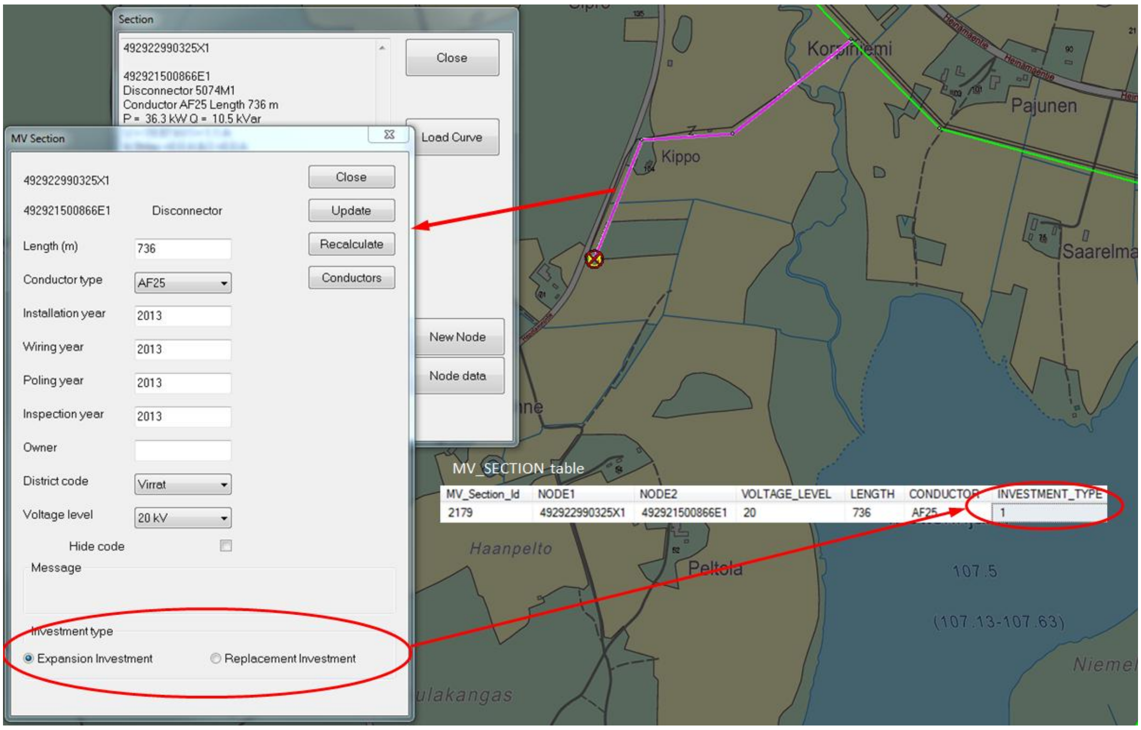


Figure 33. MV section dialog box and its record in MV_SECTION table.

At database level, 'INVESTMENT_TYPE' column is created for different component tables, containing either NULL, 1 or 2 as its value. With the help of 'INVESTMENT_TYPE' column and its value, network investments can be reported according to its type, using DMS600 Reporting Services, as presented later in the thesis.

8.9 Additional Information to Conductor Data

In network asset reporting for Energy Authority, MV and LV underground cables and overhead lines are required to be grouped by their size and type, e.g. overhead line with covered conductors 35-70 mm^2 or underground cables 150-185 mm^2. In the present DMS600 implementation, free form 'Code' field alongside with the 'Info' field are only columns in database that individualize different conductors from each other. 'Code' field is filled by end-user, DSO-specifically. Hence, different conductor types in the summary reports must be grouped by the DSO-specific 'CONDUCTOR' column of the line section table. Thus lines can't be reported directly like required in Energy Authority's web-portal.

In the DMS600 4.4 FP1 HF1 version 'Conductor material', 'Conductor size' and 'Number of bundled conductors' fields are added to MV and LV conductors dialog boxes. Also 'MATERIAL', 'CONDUCTOR_SIZE' and 'BUNDLED_CONDUCTORS' columns are created to MV and LV conductor database tables. Hence, the conductor data can be built from different fields and the conductor reports for Energy Authority can be generated with DMS600 Reporting Services, grouping the desired conductor sizes and types in authority's format. DMS600 4.4 FP1 HF1 program version's MV section and MV conductor dialog boxes with new fields are presented in Figure 34.

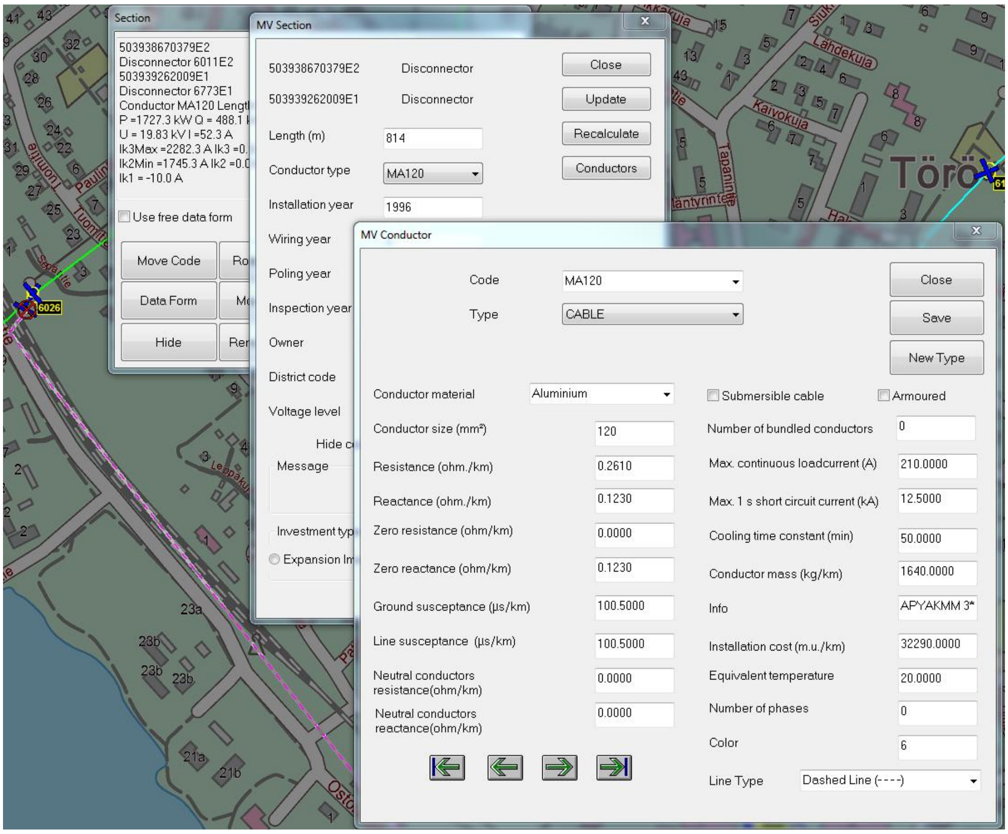


Figure 34. New MV conductor dialog box in DMS600 4.4 FP1 HF1.

New conductor materials can be found from the drop-down menu on the conductor dialog box, after they have been added to the CODEINFO table of the network database.

Checkboxes for submersible and armored cables were also created in the dialog boxes. Hence, submersible cables can be separated from the underground cables and be reported as required, using the 'SUBMERSIBLE' column from the conductor tables.

8.10 Implemented Reports

As a part of the thesis, several new reports for Energy Authority were created, such as reports required in the distribution network development plans, reports of excavation classes for underground cables and reports for investment types of network assets. Reports were created in the DMS600 Reporting Services with MS Visual Studio 2013.

8.10.1 Distribution Network Development Plan Reports

Distribution network development plan reports were created partly for sections 2 and 3.

In section 2, data concerning DSOs' future investment and maintenance costs for years 2014-2019, 2020-2023 and 2024-2028 are required. With the created report, only investment costs for MV and LV lines as well as distribution substations can be produced, because they are saved to database. In the implemented report, the embedded SQL query searches the investment costs from the NETWORK_PLAN table using the title of the plans, hence the development plans must be named accurately in right format. An example of implemented report is shown in Figure 35.

Energiavirasto - Kehittämissuunnitelmat
Liite 2 - Sähkönjakeluverkon pitkän aikavälin suunnitelma toiminnan laatuvaatimusten täyttämiseksi

1. Jakeluverkon investoinnit laatuvaatimusten täyttämiseksi

KJ-verkon investoinnit		
a) vuosina 2014 - 2019	59495	€
b) vuosina 2020 - 2023	239875	€
c) vuosina 2024 - 2028	449985	€
Muuntamoinvestoinnit		
a) vuosina 2014 - 2019	6170	€
b) vuosina 2020 - 2023	23500	€
c) vuosina 2024 - 2028	33310	€
PJ-verkon investoinnit		
a) vuosina 2014 - 2019	4672.3	€
b) vuosina 2020 - 2023	3438.94	€
c) vuosina 2024 - 2028	2389.93	€

Figure 35. Implemented report for section 2 of the development plan.

In section 3, data concerning existing distribution network from the aspect of reliability requirements is required. Length and cabling rates of MV and LV networks as well as the network length fulfilling the reliability requirements are required. Also the number of metering points located in the town plan and not town areas as well as number of metering points that meet the set reliability requirements are reported. In addition, the amount of overhead lines located in the forest as well as between road and forest in MV and LV voltage levels are required. Report for section 3 was much easier to create, because data can be queried from component tables of permanent database. Figure 36 shows an example of implemented report for section 3.

Energiavirasto - Kehittämissuunnitelma
Liite 3 - Sähkönjakeluverkon nykytilanne toiminnan laatuvaatimusten kannalta

2. Jakeluverkon pituus		
a) KJ	1985.88	km
b) PJ	2395.36	km
3. Laatuvaatimukset täyttävän jakeluverkon pituus		
a) KJ	81.48	km
b) PJ	29.37	km
4. Asemakaava-alueella sijaitsevat käyttöpaikat	2489	kpl
5. Asemakaava-alueella sijaitsevat käyttöpaikat, jotka täyttävät laatuvaatimukset	689	kpl
6. Asemakaava-alueen ulkopuolella sijaitsevat käyttöpaikat	13484	kpl
7. Asemakaava-alueen ulkopuolella sijaitsevat käyttöpaikat, jotka täyttävät laatuvaatimukset	28	kpl
8. Jakeluverkon kaapelointiasteet		
a) KJ	1.59	%
b) PJ	24.30	%
9. Metsässä sijatsevat ilmajohdot		
a) KJ	454	km
b) PJ	808	km

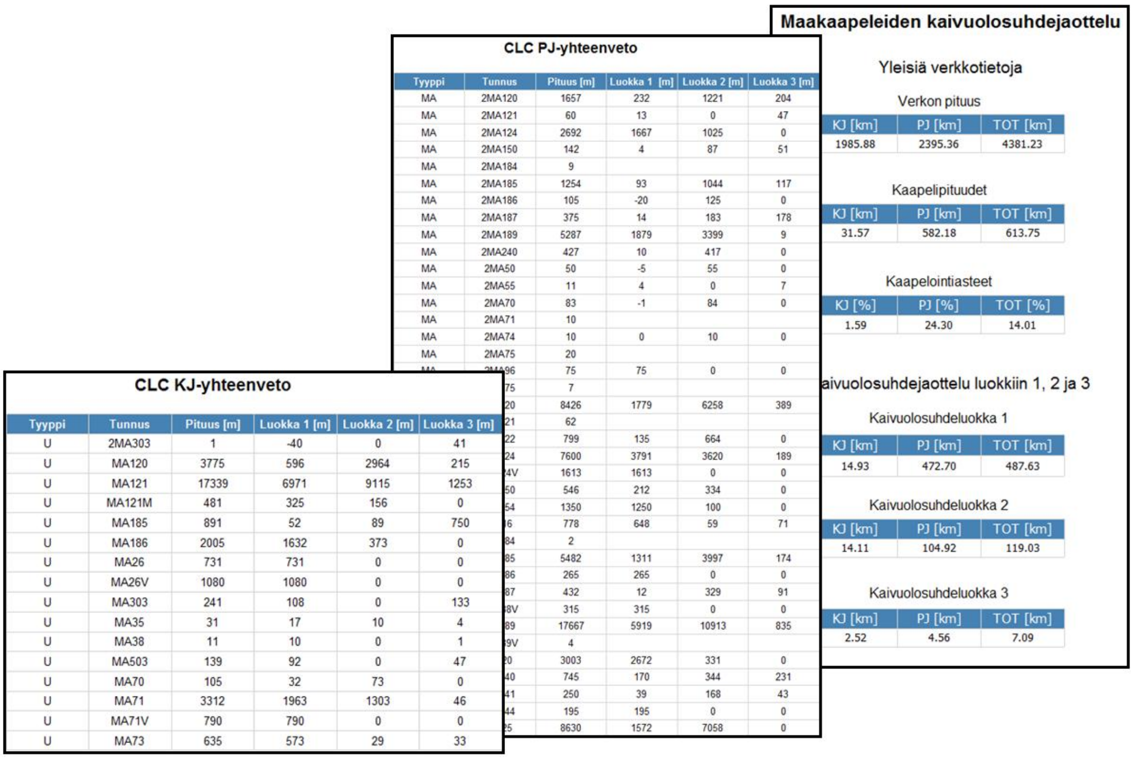
Figure 36. Implemented report for section 3 of the development plan.

Length and cabling rates of MV and LV networks are calculated directly from the line section and conductor tables. Number of metering points in the town plan area and outside the town plan area as well as the length of MV and LV overhead lines in the forest can be calculated from the METADATA_NODE and line section tables, after the shapefile analyses. Length of the MV and LV network as well as number of metering points fulfilling the reliability requirements can be calculated with the algorithms described previously. Developed algorithms aren’t implemented in the DMS600 software yet, thus they can’t be calculated automatically. MV and LV lines as well as metering points fulfilling the reliability requirements shown in Figure 36 are set to database manually for demo purposes.

8.10.2 Excavation Classes

Amount of underground cable in excavation classes one, two and three are calculated and saved to database utilizing CLC data and developed ShapefileTool. Excavation class four isn’t calculated with computer, due to verbal definitions and duplicate CLC classes with excavation class three. ShapefileTool saves the results of the CLC analysis in ‘CLC2’ and ‘CLC3’ columns of MV and LV line section tables; hence, the lengths are easily queried with DMS600 Reporting Services reports.

Three different reports were created; report of different MV underground cable types in each excavation class, report of different LV underground cable types in each excavation class as well as summary report of MV and LV underground cables. Created reports are shown in Figure 37.



Maakaapeleiden kaivuolosuhdejaottelu

Yleisiä verkkotietoja

Verkon pituus

KJ [km]	PJ [km]	TOT [km]
1985.88	2395.36	4381.23

Kaapelipituudet

KJ [km]	PJ [km]	TOT [km]
31.57	582.18	613.75

Kaapelointiasteet

KJ [%]	PJ [%]	TOT [%]
1.59	24.30	14.01

aivuolosuhdejaottelu luokkiin 1, 2 ja 3

Kaivuolosuhdeluokka 1

KJ [km]	PJ [km]	TOT [km]
14.93	472.70	487.63

Kaivuolosuhdeluokka 2

KJ [km]	PJ [km]	TOT [km]
14.11	104.92	119.03

Kaivuolosuhdeluokka 3

KJ [km]	PJ [km]	TOT [km]
2.52	4.56	7.09

CLC PJ-yhteenveto

Tyyppi	Tunnus	Pituus [m]	Luokka 1 [m]	Luokka 2 [m]	Luokka 3 [m]
MA	2MA120	1657	232	1221	204
MA	2MA121	60	13	0	47
MA	2MA124	2692	1667	1025	0
MA	2MA150	142	4	87	51
MA	2MA184	9			
MA	2MA185	1254	93	1044	117
MA	2MA186	105	-20	125	0
MA	2MA187	375	14	183	178
MA	2MA189	5287	1879	3399	9
MA	2MA240	427	10	417	0
MA	2MA50	50	-5	55	0
MA	2MA55	11	4	0	7
MA	2MA70	83	-1	84	0
MA	2MA71	10			
MA	2MA74	10	0	10	0
MA	2MA75	20			
MA	2MA96	75	75	0	0
	75	7			
	20	8426	1779	6258	389
	21	62			
	22	799	135	664	0
	24	7600	3791	3620	189
	4V	1613	1613	0	0
	50	546	212	334	0
	54	1350	1250	100	0
	6	778	648	59	71
	84	2			
	85	5482	1311	3997	174
	86	265	265	0	0
	87	432	12	329	91
	8V	315	315	0	0
	89	17667	5919	10913	835
	9V	4			
	0	3003	2672	331	0
	40	745	170	344	231
	41	250	39	168	43
	44	195	195	0	0
	5	8630	1572	7058	0

CLC KJ-yhteenveto

Tyyppi	Tunnus	Pituus [m]	Luokka 1 [m]	Luokka 2 [m]	Luokka 3 [m]
U	2MA303	1	-40	0	41
U	MA120	3775	596	2964	215
U	MA121	17339	6971	9115	1253
U	MA121M	481	325	156	0
U	MA185	891	52	89	750
U	MA186	2005	1632	373	0
U	MA26	731	731	0	0
U	MA26V	1080	1080	0	0
U	MA303	241	108	0	133
U	MA35	31	17	10	4
U	MA38	11	10	0	1
U	MA503	139	92	0	47
U	MA70	105	32	73	0
U	MA71	3312	1963	1303	46
U	MA71V	790	790	0	0
U	MA73	635	573	29	33

Figure 37. Implemented excavation class reports for underground cables.

The amount of cable in the excavation class one in the created reports is calculated subtracting the sum of excavation classes two and three from the total length of the line section.

8.10.3 Investment Types

In 3rd regulatory period, network investments have to be divided into expansion and replacement investments and reported to Energy Authority annually. Investment types of the different network components are saved to the component database tables in DMS600 4.4 FP1 HF1 version; hence they can be easily queried using ‘INVESTMENT_TYPE’ column and reported with DMS600 Reporting Services.

Investment type reports were created for MV and LV lines as well as for the most typical network component types, such as primary transformers, distribution substations and transformers, disconnectors, breakers, link boxes, et cetera. In DMS600

Reporting Services, user chooses the desired component type and gives the wiring or installation year of the component as a parameter for the query. Subsequently reporting tool produces summary list of the component type presenting investment type, code, type, length, owner, et cetera. Figure 38 shows an example of investment type reports for distribution substations and MV line sections.

Jakelumuuntamot

Investointityyppi	Tunnus	Tyyppi	Omistaja
Laajennus	3077	Y0P2V	OMA
Laajennus	3118	P1P3V	OMA
Laajennus	3140	Y1P3V	OMA
Laajennus	3192	ECOSAFE	OMA
Laajennus	3206	Y1P2V	OMA
Laajennus	4039	P1P3V	OMA
Laajennus	4050	Y1L2V	O
Laajennus	4144	Y1P1V	O
Korvaus	3055	P1P4V	O
Korvaus	3067	P1L3A	O
Korvaus	3156	Y1L1V	O
Korvaus	3174	Y1P2V	O
Korvaus	3199	Y1K1V	O
Korvaus	3204	Y1L2V	O
Korvaus	4084	Y1P3V	O
Korvaus	4086	Y1P2V	O
Korvaus	4118	P1P2V	O
Korvaus	4140	Y1P1V	O

KJ-johdinlajit

Investointityyppi	Johdinlaji	Pituus
Korvaus	AF40	500
Korvaus	AF40	647
Korvaus	AF40	1303
Korvaus	AF40	1423
Korvaus	MA121	145
Laajennus	AF40	1
Laajennus	AF62	756
Laajennus	AF62	1019
Laajennus	MA121	489
Laajennus	PS70	620
Laajennus	PS70	865

Figure 38. Implemented investment type reports for distribution substations and MV line sections.

8.11 Summary of Developed Solutions and Methods

Most of the developed solutions and methods presented in this Chapter were already implemented to DMS600 software during the thesis process, but some solutions were left only in theoretical, specification level. Implementations are done in DMS600 4.4 FP1 HF1 program version, which will be released at end of 2014.

Table 5 summarizes the developed methods and solutions and shows the state of solution, i.e. is the solution or method already implemented or just specification. Also the subchapter in the thesis is given.

Table 5. Summary of developed solutions and methods.

Developed solution or method	State	Subchapter
Metering point-specific outage reporting model	Implemented	8.1
ShapefileTool	Implemented	8.2
AreaImportTool	Implemented	8.3
Calculating the metering points in the town plan area	Implemented	8.2.1 and 8.4.1
Calculating the overhead lines in the forest	Implemented	8.2.1 and 8.4.2
Calculating the overhead lines between road and forest	Specification	8.4.3
Excavation class calculation for underground cables	Implemented	8.2.2 and 8.4.5
Algorithms for DRR fulfillment	Specification	8.5.1
CELID index calculation	Specification	8.5.2
History Analysis	Specification	8.5.3
Demolition of network components	Specification	8.6
Network history database	Specification	8.7
Investment type division and reporting	Implemented	8.8
Additional information to conductor data	Implemented	8.9

The described solutions and methods that were left only in specification or theoretical level will be implemented in future and this thesis provides the basis for the developer and supports in development work.

9. CONCLUSION

This thesis studied the development of ABB MicroSCADA Pro product portfolio's Network Information System and Distribution Management System from the aspect of Energy Authority and ET reporting requirements. Objective of the thesis were to develop methods to DMS600 Network Editor and Workstation software that enable proper data gathering for Finnish DSOs' reporting purposes. Different background map materials that can be utilized in data reporting were studied as well, and the most important reporting requirements for Energy Authority and ET were also collected to this thesis.

Developed ShapefileTool and AreaImportTool enable environmental analysis for DSO's network assets, based on Esri shapefiles. ShapefileTool analyzes given shapefile data and network information, all line sections and nodes within shapes are written to database and can queried using MS SQL Server-based reporting tool, DMS600 Reporting Services. Hence, e.g. metering points located in the town plan area or overhead lines in the forest can be calculated and reported, like Energy Authority and ET require. Also the amount of underground cable in different excavation classes can be calculated with the tool. Polygon areas of the analyzed shapefiles, e.g. town plans, can be imported to database by means of AreaImportTool. After the import, areas are graphically visible upon background map.

Fair amount of usable open data for environmental analysis and reporting purposes were found. The challenge in open data mostly is the data format and data content diversity. Town plan area and CLC data are provided directly in vector format and the data content is unique, thus straight usage for DMS600's purposes is enabled. Forestry data, in turn, is provided in raster format; hence the data must be converted to vector format manually before it can be utilized in reporting. Also data classes must be named by user, posing that no generic reports could be created for all DMS600 users.

The most essential question relating to new Electricity Market Act and distribution network development plan requirement in the thesis viewpoint was how to analyze the distribution reliability requirements fulfillment in the distribution network. Network structure that fulfills the reliability requirements isn't determined by Electricity Market Act or Energy Authority, thus DSOs can define the criterion by themselves. This criterion was the major theme in the interviews with the representatives of three Finnish DSOs. Based on information gained from interviews, two algorithms to analyze the distribution reliability fulfillment were developed; one for MV and LV line sections and one for metering points in LV network.

Several changes to DMS600's data saving functions and modifications to database structure are needed. Hence, adequate data for network development plans can be reported like required. Also investment type division, demolition of components, network history database and additional conductor information, enable data reporting according to requirements and directly in right format. Altering the outage data saving model in metering point level, makes the reporting for ET possible onwards 2015, according to new requirement.

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APPENDIX A: QUESTIONNAIRE FORM FOR ENERGY AUTHORITY

1)	What has been driver for Electricity Market Act reform? • 51 § Distribution reliability Requirements • 52 § Distribution network development plans
2)	In the article 51 § distribution reliability requirements, why the act takes a stance only to interruptions caused by storm or snow load? Why it isn't interruptions caused by any reason?
3)	In the article 51 § distribution reliability requirements, the areas under consideration are town plan area and not town plan area. Why not city, urban area and rural area?
4)	How the percentages of DSOs' customers have to be defined during the transition period of distribution reliability requirements? Beforehand or Afterwards? Or how?
5)	How DSOs should verify the reliability requirements fulfillment?
6)	When reporting the investment costs in the distribution network development plans, should the unit prices of the network components determined Energy Authority be used?
7)	How accurate the reported investment costs should be in the development plans? Are estimated values enough?
8)	Overhead lines located between roads and forests have to be reported in the development plans. This will be very challenging to the DMS/NIS developers. Do Energy Authority have any recommendation to the distance from the road to the overhead line such that the overhead line can still be considered to be located by the roadside?
9)	The fulfillment of the planned network investment is monitored in the section 5, will DSOs get punished if the planned investments reported in section 4 don't come true?
10)	Are there any changes coming to the development plan reporting in the future that are already known?

APPENDIX B: QUESTIONNAIRE FORM FOR DISTRIBUTION SYSTEM OPERATORS

1)	What is DSO's opinion on the new Electricity Market Act and authority's new requirements? • 51 § Distribution reliability requirements • 119 § Transitional Provision to distribution reliability requirements • 52 § Distribution network development plans Are they really necessary?
2)	Did the new act and new requirements come into effect too short notice?
3)	What is behind the new act and new requirements?
4)	What is the objective of new act and requirements?
5)	What is DSO's strategy in network planning and development to reach the requirements set in the law?
6)	Are the areas under consideration in the reliability requirements, town plan area and not town plan area rational, compering to area division city, urban area and rural area?
7)	How the reliability requirements fulfillment should be verified/calculated/modeled?
8)	Should NIS calculate/model the reliability requirements fulfillment automatically or should this be done manually by user?
9)	At the present there is no software solution to do this, how you'll now verify the requirements fulfillment?
10)	Should NIS include advanced reliability analysis tool? Do you find it important? Could the tool be useful in modeling/verifying the reliability requirements fulfillment? Could the tool be used in network development planning in general? How?
11)	What functionalities and features should the reliability analysis tool include?
12)	Have you used the existing reliability analysis tool in NIS?
13)	Do you find the present tool useful at all?
14)	What kind of background material would you want to be brought to NIS? For what purpose?
15)	Do you find the present network planning functions adequate? How the planning functions should be developed?
16)	Are the NIS's present planning functions useful when doing the network development plans?
17)	What kind of system DSO wants to be developed for development plan reporting?
18)	Are you satisfied to present authority reporting tool (DMS600 Reporting Services)? Would you stop using old MS Access-based reporting tool?
19)	How the DMS600 Reporting Services should be developed?
20)	Should the amount of underground cables in different excavation classes be able to be calculated using NIS?

APPENDIX C: FIGURES DESCRIBING THE ELECTRICITY DISTRIBUTION NETWORK ACTIVITY

Nature and Scope of Distribution Network Activity

1)	Distributed energy in DSO's 0.4 V network (including also 0.1 kV networks), 1–70 kV network, 110 kV network and total amount of distributed energy [GWh] a) Distributed energy to end-users b) Distributed energy to other DSOs c) Received energy from power plants d) Received energy from other DSOs
2)	The highest received hour average power [MW]
3)	The length of the network in different voltage levels [km] a) 0.4 kV network b) 1-70 kV network c) 110 kV network
4)	Number of metering points in different voltage levels at the last day of the year under consideration [pcs] a) Metering points connected to 0.4 kV network b) Metering points connected to 1-70 kV network c) Metering points connected to 110 kV network
5)	Number of network service points in different voltage levels at the last day of the year under consideration [pcs] a) Network service points connected to 0.4 kV network b) Network service points connected to 1-70 kV network c) Network service points connected to 110 kV network
6)	Number of DSO's own employees in the distribution network activity [pcs]
7)	Cabling rate of the distribution network in different voltage levels [%] a) Cabling rate of the 0.4 kV network b) Cabling rate of the 1-70 kV network c) Cabling rate of the 110 kV network
8)	Number and capacity of substations and transformers in different voltage levels a) Number of substations, U_n < 110 kV [pcs] b) Number of substations, $U_n \geq$ 110 kV [pcs] c) Number of transformers, U_n < 110 kV [pcs] d) Number of transformers, $U_n \geq$ 110 kV [pcs] e) The capacity of transformers, U_n < 110 kV [MVA] f) The capacity of transformers, $U_n \geq$ 110 kV [MVA]
9)	Total number of distribution substations [pcs]

Indices of Quality of Distribution Network Activity

17) Customer's average annual duration of interruptions weighted by annual energies, caused by unanticipated interruptions in the 1–70 kV network in year *t* [h/a]
18) Customer's average annual number of interruptions weighted by annual energies, caused by unanticipated interruptions in the 1–70 kV network in year *t* [pcs]
19) Customer's average annual duration of interruptions weighted by annual energies, caused by planned interruptions in the 1–70 kV network in the year *t* [h/a]
20) Customer's average annual number of interruptions weighted by annual energies, caused by planned interruptions in the 1–70 kV network in year *t* [pcs]
21) Customer's average annual number of interruptions weighted by annual energies, caused by delayed autoreclosings in the 1–70 kV network in year *t* [pcs]
22) Customer's average annual number of interruptions weighted by annual energies, caused by rapid autoreclosings in the 1–70 kV network in year *t* [pcs]
23) Customer's annual duration of interruptions [h/a] a) Customer's average annual duration of interruptions caused by fault in DSO's own 1-70 kV network including delayed autoreclosings b) Customer's average annual duration of interruptions caused by other reason in DSO's 1-70 kV network including delayed autoreclosings
24) Customer's average annual number of interruptions [pcs] a) Customer's average annual number of interruptions caused by fault in DSO's own 1-70 kV network including delayed autoreclosings b) Customer's average annual number of interruptions caused by other reason in DSO's 1-70 kV network including delayed autoreclosings
25) Total annual number of sustained unanticipated interruptions in the 0.4 kV network [pcs]
26) Total annual number of unanticipated interruptions including rapid and delayed auto-reclosings in the 1-70 kV network [pcs]
27) Annual amount of paid outage compensation divided by interruption durations [€] • 12-24 h • 24-72 h • 72-120 h • over 120h
28) Annual number of outage compensated customers divided by interruption durations [pcs] • 12-24 h • 24-72 h • 72-120 h • over 120h

APPENDIX D: NETWORK ASSET REPORTING

Distribution substations • 1-pole-mounted distribution substation • 2-pole-mounted distribution substation • 4-pole-mounted distribution substation • Light modular pad-mounted distribution substation • Pad-mounted distribution substation, maintained outside the substation • Pad-mounted distribution substation, maintained inside the substation • Indoor building distribution substation • Special distribution substation • Cabled disconnector station • 1 kV protection devices
Transformers • 20/10 kV transformers • 16 kVA • 30 kVA • 50 kVA • 100-160 kVA • 200 kVA • 300-315 kVA • 500-630 kVA • 800 kVA • 1 000 kVA • 1 250 kVA • 1 600 kVA • 10/20 kV transformers • 45/20 kV transformers • 20/20 kV regulating transformer
20 kV overhead lines • Sparrow (ACSR 34/6 mm^2) or thinner • Raven (ACSR 54/9 mm^2) • Pigeon (ACSR 85/14 mm^2) • Al 132 or thicker • Aerial cable 70 mm^2 or thinner • Aerial cable 95 mm^2 or thicker • Covered conductor overhead line 35–70 mm^2 • Covered conductor overhead line 95 mm^2 or thicker • Other 20 kV overhead line conductor types
0.4 kV overhead lines • AMKA (aerial bunched cables) 16-25 mm^2 • AMKA (aerial bunched cables) 35-50 mm^2 • AMKA (aerial bunched cables) 70 mm^2 • AMKA (aerial bunched cables) 120 mm^2

- Other 0.4 kV overhead line conductor types

20 kV disconnectors and reclosers

- 1-phased line disconnector
- Line disconnector
- Line disconnector with breaking chamber
- Remote controlled disconnector station, one disconnector
- Remote controlled disconnector station, two disconnectors
- Remote controlled disconnector station, 3-4 disconnectors
- Pole-mounted recloser (remote controlled)
- 20 kV switching station
- 20/20 kV regulating station

20 kV underground cables (mounting)

- Cable, max cross-sectional area 70 mm^2
- Cable 95-120 mm^2
- Cable 150-185 mm^2
- Cable 240-300 mm^2
- Cable 400-500 mm^2
- Cable 630-800 mm^2
- Submersible cable, max cross-sectional area 70 mm^2
- Submersible cable 95-120 mm^2
- Submersible cable 150-185 mm^2
- Switchgear terminal
- Pole terminal
- Cable joint

0.4 kV underground cables (mounting)

- Cable, max cross-sectional area 25 mm^2
- Cable 35-50 mm^2
- Cable 70 mm^2
- Cable 95-120 mm^2
- Cable 150-185 mm^2
- Cable 240-300 mm^2
- Submersible cable, max cross-sectional area 35 mm^2
- Submersible cable 50-70 mm^2
- Submersible cable 95-120 mm^2
- Submersible cable, cross-sectional area at least 150 mm^2

Excavation classes for underground cables

1. Easy (e.g. rural areas)
2. Regular (e.g. urban areas)
3. Difficult (e.g. center areas of the cities)
4. Extremely difficult (e.g. nuclear center areas of the metropolises)

Cable boxes and fuse switches

- Branching box
- Cable box, nominal current 0-400 A

• Cable box, nominal current at least 630 A • Fuse switch, nominal current 0-160 A • Fuse switch, nominal current of 250-400 A • Fuse switch, nominal current 630 A
45 kV substation structures • 45/20 kV substations • 45 kV switchgears in the 110 kV substations • 45 kV switchgears in the 110 kV substations + additional switchgears
110 kV primary transformers • 6 MVA • 10 MVA • 16 MVA • 20 MVA • 25 MVA • 31.5 MVA • 40 MVA • 50 MVA • 63 MVA • 80 MVA • 100 MVA • 220/110 kV transformer
110 kV light modular substations • 110 kV light modular substation
Other network components • Capacitor bank, nominal reactive power 2.4 MVAR • Earth fault compensation system, 100 A • Earth fault compensation system, 100 A with grounding transformer • Earth fault compensation system, 140 A • Earth fault compensation system, 140 A with grounding transformer • Earth fault compensation system, 250 A • Earth fault compensation system, 250 A with grounding transformer • Reactor, nominal apparent power 0-50 MVA • Reactor, nominal apparent power over 50 MVA • Reserve power generator, nominal apparent power 50-100 MVA • Reserve power generator, nominal apparent power 250-350 MVA • Reserve power generator, nominal apparent power 700-1 000 MVA

APPENDIX E: VERBAL DEFINITIONS FOR THE EXCAVATION CLASSES

1. Easy (e.g. rural areas) • Minimal traffic • Not much pavement • Easy excavation environment • Not much other networks • Areas outside the town plans • Small villages and service centers • Mainly sparse single-housing • Not much roads
2. Regular (e.g. urban areas) • Edge zones of the city centers • Center areas of the district centers • Paved road and street areas • Small number of other networks to look out for • Service centers • A lot of reserved areas for different purposes (e.g. sport parks, ice rinks, etc.) • Many buildings
3. Difficult (e.g. center areas of the cities) • A lot of pedestrian and vehicle traffic • On-street parking • Activities during day and night times • Business and offices • Special-paved areas • Mechanical excavation requires ditchdigger • Several other networks, placing is difficult • Multistorey buildings constructed densely • Public transport in the area • Rocky areas (mining needed) • Excavation requires earth moving
4. Extremely difficult (e.g. nuclear center areas of the metropolises) • A lot of pedestrian and vehicle traffic • On-street parking • Activities during day and night time • Business and offices • Mechanical excavation requires ditchdigger • Several other networks, placing is difficult • Special-paved areas (e.g. pavements) • Multistorey buildings and apartment houses constructed extra-densely • A lot of public transport in the area • A lot of action below ground and underground car parks • Excavation requires earth moving and expensive special arrangements for traffic • A lot of special pavements • Area's average building efficiency is considerably higher than in the city

- Work must be timed mostly in the night times

APPENDIX F: DISTRIBUTION NETWORK DEVELOPMENT PLAN REPORT

Section 1 - Strategic Basis of the Distribution Network Development Plan

1) What is DSO's network planning strategy to fulfill the distribution reliability requirements for metering points located in the town plan area?
2) What are DSO's methods to fulfill the distribution reliability requirements in the town plan area? *The most essential network investments and preventive maintenance actions that will be applied in the HV, MV and LV networks have to come out in the report*
3) What is DSO's network planning strategy to fulfill the distribution reliability requirements for metering points located outside the town plan area?
4) What are DSO's methods to fulfill the distribution reliability requirements outside the town plan area? *The most essential network investments and preventive maintenance actions that will be applied in the HV, MV and LV networks have to come out in the report*
5) What parts of the distribution network DSO's actions are directed? a) between years 2014–2019 b) between years 2020–2023 c) between years 2024–2028
6) How DSO is prepared to network planning and network construction?
7) How DSO collaborates with the quarters that build and maintain other community infrastructure networks?
8) What kind of network maintenance plan DSO has?
9) What are DSO's resources for fault clearance? a) in every day actions b) in faults that are due storm or snow load according to the article 51 §
10) How the important customers from the society point of view are taken into account in the distribution network development?
11) DSO's applied local distribution reliability requirements for the customers defined in 2nd moment of the article 51 § a) Number of metering points where local distribution reliability requirement level can be applied differing from the 3rd section of the 1st moment of the article 51 § b) Number of metering points where DSO will apply local distribution reliability requirement level differing from the 3rd section of the 1st moment of the article 51 § c) How DSO defines the applied local distribution reliability requirement level if the reliability requirement level differs from the 3rd section of the 1st moment of the article 51 §? d) What is the local distribution reliability requirement level applied?

Section 2 - Long-term Distribution Network Development Plan to Meet the Distribution Reliability Requirements

1) How much DSO invests and spends money to network maintenance to meet the distribution reliability requirements according to transition periods set in article 119 §? [€]
    a) HV network
        i. investments
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
        ii. maintenance
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
    b) Substations
        i. investments
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
        ii. maintenance
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
    c) MV network
        i. investments
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
        ii. maintenance
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
    d) Distribution substations
        i. investments
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
        ii. maintenance
            a. between years 2014–2019
            b. between years 2020–2023
            c. between years 2024–2028
    e) LV network
        i. investments
            a. between years 2014–2019

b. between years 2020–2023
c. between years 2024–2028

ii. maintenance

a. between years 2014–2019
b. between years 2020–2023
c. between years 2024–2028

2) How much distribution network will be changed to meet the distribution reliability requirements according to transition periods set in article 119 §? [km]

a) MV network

a. between years 2014–2019
b. between years 2020–2023
c. between years 2024–2028

b) LV network

a. between years 2014–2019
b. between years 2020–2023
c. between years 2024–2028

3) How many metering points located in the town plan area will be moved to be supplied by network which meets the distribution reliability requirements according to transition periods set in article 119 §? [pcs]

a. between years 2014–2019
b. between years 2020–2023
c. between years 2024–2028

4) How many metering points located outside the town plan area will be moved to be supplied by network which meets the distribution reliability requirements according to transition periods set in article 119 §? [pcs]

a. between years 2014–2019
b. between years 2020–2023
c. between years 2024–2028

5) What are the cabling rates in different voltage levels after the actions according to transition periods set in article 119 §? [%]

a) MV network

a. 1.1.2020
b. 1.1.2024
c. 1.1.2029

b) LV network

a. 1.1.2020
b. 1.1.2024
c. 1.1.2029

Section 3 - Present Situation of the Distribution Network from the Aspect of Distribution Reliability Requirements

1)	Geographical map of the MV network where the parts of the network are highlighted that meet the distribution reliability requirements. *Map is required first time with the development plan in 2020, describing the situation in network at the January 1st 2020.*
2)	Length of the distribution network in different voltage levels [km] a) MV b) LV
3)	Length of the distribution network in different voltage levels that meets the distribution reliability requirements [km] a) MV b) LV
4)	Number of metering points located in the town plan area [pcs]
5)	Number of metering points located in the town plan area supplied by the distribution network that meets the distribution reliability requirements [pcs]
6)	Number of metering points located outside the town plan area [pcs]
7)	Number of metering points located outside the town plan area supplied by the distribution network that meets the distribution reliability requirements [pcs]
8)	Cabling rate of the distribution network in different voltage levels [%] a) MV network b) LV network
9)	Length of the overhead lines in different voltage levels located in the forest [km] a) MV network b) LV network
10)	Length of the overhead lines in different voltage levels located between the road and forest [km] a) MV network b) LV network

Section 4 - Distribution Network Plan for Present and Next Year to Meet the Distribution Reliability Requirements

1) How much DSO will invest and spend money to network maintenance to meet the distribution reliability requirements during present and next year [€] a) HV network i. investments ii. maintenance a) Substations i. investments ii. maintenance b) MV network i. investments ii. maintenance c) Distribution substations i. investments ii. maintenance d) LV network i. investments ii. maintenance
2) What are the actions to change the distribution network located in the town plan area to meet the distribution reliability requirements during present and next year? a) HV network and substations b) MV network and distribution substations c) LV network
3) What are the actions to change the distribution network located outside the town plan area to meet the distribution reliability requirements during present and next year? a) HV network and substations b) MV network and distribution substations c) LV network
4) How much distribution network will be changed to meet the distribution reliability requirements during present and next year? [km] a) MV network b) LV network
5) Number of metering points located in the town plan area that will be moved to be supplied by the distribution network which meets the distribution reliability requirements during present and next year [pcs]
6) Number of metering points located outside the town plan area that will be moved to be supplied by the network which meets the distribution reliability requirements during present and next year [pcs]
7) Cabling rate of the distribution network in different voltage levels during present and next year [%] a) MV network b) LV network

Section 5 - Network Investments in Past Two Years to Meet the Distribution Reliability Requirements

1)	How much DSO invested and spent money to network maintenance to meet the distribution reliability requirements in past two years? [€] a) HV network i. investments ii. maintenance b) Substations i. investments ii. maintenance c) MV network i. investments ii. maintenance d) Distribution substations i. investments ii. maintenance e) LV network i. investments ii. maintenance
2)	What were the actions applied to change the distribution network located in the town plan area to meet the distribution reliability requirements in past two years? a) HV network and substations b) MV network and distribution substations c) LV network
3)	What were the actions applied to change the distribution network located outside the town plan area to meet the distribution reliability requirements in past two years? a) HV network and substations b) MV network and distribution substations c) LV network
4)	How much distribution network was changed to meet the distribution reliability requirements in past two years? [km] a) MV network b) LV network
5)	How many metering points located in the town plan area were moved to be supplied by network which meets the distribution reliability requirements in past two years? [pcs]
6)	How many metering points located outside the town plan area were moved to be supplied by network which meets the distribution reliability requirements in past two years? [pcs]

APPENDIX G: GENERAL INFORMATION REPORT

2. MV LINE LENGTHS

			Rural area *) CR < 30 %	Urban area *) CR 30-75 %	City *) CR > 75 %	Total
Overhead line	2.1	km				
Overhead line with covered conductors (PAS)	2.2	km				
Aerial cable	2.3	km				
Underground cable	2.4	km				
TOTAL MV LENGTH	2.5	km				
- DAR and/or RAR protected line	2.6	km				

*) Division to rural areas, urban areas and city areas is made by feeders according to cabling rate (CR).

All distribution substations and metering points of one feeder are classified according to the cabling rate

not depending on their real location

			Neutral isolated	Partly compensated	Compensated	Total
Overhead line	2.7	km				
Overhead line with covered conductors (PAS)	2.8	km				
Aerial cable	2.9	km				
Underground cable	2.10	km				
TOTAL MV LENGTH	2.11	km				
- DAR and/or RAR protected line	2.12	km				

3. FAULTS CLEARED BY RECLOSINGS

Delayed autoreclosings

			Rural area	Urban area	City	Total
Number	3.1	pcs				
Kpk	3.2	pcs				
Mph	3.3	h				
Mpk	3.4	pcs				
Empk	3.5	MWh				

Rapid autoreclosings

Number	3.6	pcs				
Kpk	3.7	pcs				
Mpk	3.8	pcs				
Empk	3.9	MWh				

Delayed autoreclosings

			Neutral isolated	Partly compensated	Compensated	Total
Number	3.10	pcs				
Kpk	3.11	pcs				
Mph	3.12	h				
Mpk	3.13	pcs				
Empk	3.14	MWh				

Rapid autoreclosings

Number	3.15	pcs				
Kpk	3.16	pcs				

Mpk	3.17	pcs				
Empk	3.18	MWh				

4. NETWORK ASSET SUMMARY

			Rural area	Urban area	City	Total
Feeding substations	4.1	pcs				
Switching stations	4.2	pcs				
Feeders	4.3	pcs				
LV networks	4.4	pcs				
Total energy of the LV networks	4.5	MWh				
Metering points	4.6	pcs				
Portion of overhead lines in the forest	4.7	%				
Portion of PAS overhead lines in the forest	4.8	%				

5. LV LINE LENGTHS AND LV ASSET SUMMARY

Overhead line	5.1	km	
Underground cable	5.2	km	
Aerial cable	5.3	km	
TOTAL LV LENGTH	5.4	km	
Number of metering points in LV network	5.5	pcs	

6. INTERRUPTIONS IN THE LV NETWORK

Unanticipated interruptions	6.1	pcs	
Planned interruptions	6.2	pcs	

APPENDIX H: OUTAGE AREA REPORT

DSO code	Outage number	Outage area	Information describing the Interruption: Interruption type	Reason of interruption	Fault location	Fault type
511	1	1	V1: Unanticipated outage in own network	L3: Thunder	A2: Overhead line network	VT1: Short circuit
511	1	2	V1: Unanticipated outage in own network	L3: Thunder	A2: Overhead line network	VT1: Short circuit
511	2	1	V1: Unanticipated outage in own network	L2: Snow or ice	A2: Overhead line network	VT2: Earth fault
511	2	2	V1: Unanticipated outage in own network	L2: Snow or ice	A2: Overhead line network	VT2: Earth fault
511	3	1	S1: Planned outage in own network	ST2: Network construction	A5: Underground cable network	

	Started						Ended						Duration	Information describing the scope of the interruption				
JLKA%	Year	Month	d	h	min	s	Year	Month	d	h	min	s	Hours	Mpk	Mpe	Mph	Kpk	Kph
10	2003	7	11	11	11	11	2003	7	11	11	21	11	0,167	3	500,000	0,500	22	3,667
10	2003	7	11	11	11	11	2003	7	11	13	21	11	2,167	1	150,000	2,000	5	10,833
0	2003	12	22	23	12	12	2003	12	22	23	32	12	0,333	2	450,000	0,667	42	14,000
0	2003	12	22	23	12	12	2003	12	23	0	12	12	2,000	1	400,000	2,000	54	108,000
100	2003	12	28	12	0	0	2003	12	28	15	0	0	3,000	1	200,000	3,000	20	60,000

APPENDIX I: GENERAL INFORMATION REPORT ONWARDS 2015

2.1 HV LINE LENGTHS

Overhead line	2.1.1	km	
Overhead line with covered conductors (PAS)	2.1.2	km	
Aerial cable	2.1.3	km	
Underground cable	2.1.4	km	
TOTAL HV LENGTH	2.1.5	km	

2.2 MV LINE LENGTHS

Overhead line	2.2.1	km	
Overhead line with covered conductors (PAS)	2.2.2	km	
Aerial cable	2.2.3	km	
Underground cable	2.2.4	km	
TOTAL MV LENGTH	2.2.5	km	

2.3 LV LINE LENGTHS

Overhead line	2.3.1	km	
Aerial cable	2.3.2	km	
Underground cable	2.3.3	km	
TOTAL LV LENGTH	2.3.4	km	

3. NETWORK ASSET SUMMARY

			Not town plan area	Town plan area	Total
Feeding substations	3.1	pcs			
Primary transformers	3.2	pcs			
Remote controlled disconnectors in distribution network	3.3	pcs			
Remote controlled reclosers in distribution network	3.4	pcs			
Total number of feeders in substations	3.5	pcs			
Number of LV networks	3.6	pcs			
Number of distribution transformers	3.7	pcs			
Total year energy of the metering points in HV network	3.8	MWh			
Total year energy of the metering points in MV network	3.9	MWh			
Total year energy of the metering points in LV network	3.10	MWh			
Number of metering points in HV network	3.11	pcs			
Number of metering points in MV network	3.12	pcs			
Number of metering points in LV network	3.13	pcs			

APPENDIX J: OUTAGE AREA REPORT ONWARDS 2015

DSO code	Outage number	Voltage level HV/MV/LV	Interruption type	Reason of interruption	Location	Fault type
			Code: Definition	Code:Definition	Code:Definition	Code:Definition
123	1	MV	V1: Unanticipated outage in own network	L3: Thunder	A2: Overhead line network	VT1: Short circuit
123	2	MV	V1: Unanticipated outage in own network	L2: Snow or ice	A2: Overhead line network	VT2: Earth fault
123	3	MV	S1: Planned outage in own network	ST2: Network construction	A5: Underground cable network	
123	4	MV	J1: RAR			
123	5	MV	J2: DAR			
123	6	LV	V1: Unanticipated outage in own network	L2: Snow or ice	A4: Aerial cable	
123	7	LV	S1: Planned outage in own LV network	ST2: Network construction	A5: Underground cable network	
123	8	HV	V1: Unanticipated outage in own feeding network	R1: Structural	A1:Substation	
123	9	HV	V2: Unanticipated outage in feeding customer network	T1: Unknown	A10: Unknown	VT7: Other fault
123	10	MV	V3: Unanticipated outage in own network due to an outage in customer network	R1: Structural	A9: Customer network	VT7: Other fault

Started						Ended						Duration	Town plan area				Not town plan area			
Vuosi	mo	d	h	min	s	Year	mo	d	h	min	s	Hours[h]	Kpk[kpl]	Kph[h]	Kpe[MWh]	KAHtot [€]	Kpk[kpl]	Kph[h]	Kpe[MWh]	KAHtot [€]
2015	3	2	10	11	12	2015	3	2	11	15	12	1,0667	22	23	300	25	10	11	150	12
2015	3	3	16	11	12	2015	3	3	17	11	12	1,0000	42	42	600	50	0	0	0	0
2015	3	5	8	1	12	2015	3	5	10	11	12	2,1667	20	43	300	51	0	0	0	0
2015	3	2	10	11	12	2015	3	2	10	11	13	0,0003	1200	0	6000	150	2400	1	16800	300
2015	3	2	10	11	13	2015	3	2	10	12	17	0,0178	1200	21	6000	250	2400	43	16800	600
2015	1	2	10	11	12	2015	1	2	18	15	12	8,0667	0	0	0	0	1	8	12	5
2015	5	3	12	11	12	2015	5	3	13	10	12	0,9833	50	49	250	300	0	0	0	0
2015	3	2	10	11	12	2015	3	2	11	15	12	1,0667	1200	1280	6000	1000	2400	2560	16800	2000
2015	3	3	16	11	12	2015	3	3	17	11	12	1,0000	2400	2400	15000	3000	4800	4800	50000	7000
2015	3	5	8	1	12	2015	3	5	8	5	12	0,0667	1200	80	6000	600	2400	160	16800	1200

APPENDIX K: METERING POINT-SPECIFIC OUTAGE REPORT

Metering point-specific outage statistics

Starting 1.1.2015

Ending 31.12.2015

DSO	GENERAL INFORMATION			FEEDING CUSTOMER NETWORK			
number	Metering point number	Reliability requirement class	Year energy (kWh)	HV - Unanticipated outages (ask, pcs)	HV - Unanticipated outages (ash, h)	MV - Unanticipated outages (ask, pcs)	MV - Unanticipated outages (ash, h)
123	1234	Town plan area	6500				
123	5678	Town plan area	12300				
123	9999	Not town plan area	34000				

OWN NETWORK

HV - Unanticipated outages (ask, pcs)	HV - Unanticipated outages (ash, h)	HV - Planned outages (ask, pcs)	HV - Planned outages (ash, h)	HV - Metering point-specific KAH (€)	MV - Unanticipated outages (ask, pcs)	MV - Unanticipated outages (ash, h)
0	0,00	0	0,00		1	1,20
0	0,00	0	0,00		2	4,88
0	0,00	0	0,00		6	12,59

MV - Planned outages (ask, pcs)	MV - Planned outages (ash, h)	MV - Metering point-specific KAH (€)	LV - Unanticipated outages (ask, pcs)	LV - Unanticipated outages (ash, h)	LV - Planned outages (ask, pcs)	LV - Planned outages (ash, h)
0	0,00	1,02	1	1,20	0	0,00
1	0,50	2,51	2	4,88	1	0,50
1	1,34	11,20	6	12,59	1	1,34

LV - Metering point-specific KAH (€)	Delayed autoreclosings (ask, pcs)	DAR - Metering point-specific KAH (€)	Rapid autoreclosings (ask, pcs)	RAR - Metering point-specific KAH (€)